3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86 percent of total emissions on a carbon equivalent basis in 2004. This included 97, 39, and 15 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 82 percent of national emissions from all sources on a carbon equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 25,575 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2002, of which the United States accounted for about 23 percent.[1] Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, as well as indirect greenhouse gases such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of these indirect greenhouse gas emissions.

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. CO_2 emissions from these activities, however, are not included in national emissions totals because biomass fuels are of biogenic origin. It is assumed that the carbon released during the consumption of biomass is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for within the Land Use, Land-Use Change, and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass-based fuels are included in national totals under stationary and mobile combustion.

Figure 3-1

2004 Energy Chapter Greenhouse Gas Sources

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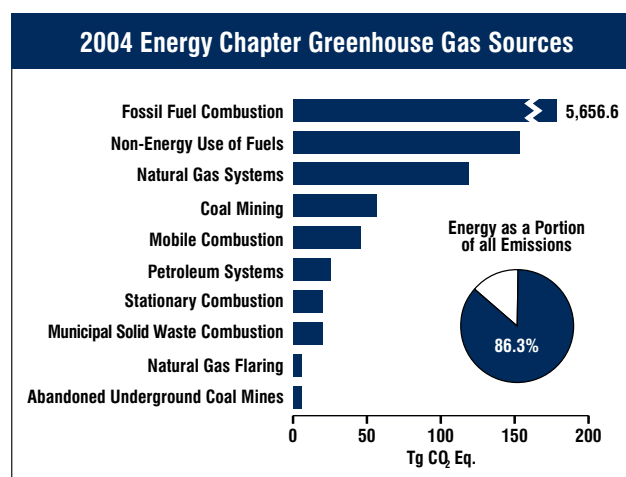
[1] Global CO_2 emissions from fossil fuel combustion were taken from Marland *et al*. (2003) <http://cdiac.esd.ornl.gov/trends/emis/meth_reg.htm>.

Table 3-1: CO$_2$, CH$_4$, and N$_2$O Emissions from Energy (Tg CO$_2$ Eq.)

Gas/Source	1990	1998	1999	2000	2001	2002	2003	2004
CO$_2$	**4,830.5**	**5,448.3**	**5,527.6**	**5,698.1**	**5,642.7**	**5,663.3**	**5,730.0**	**5,835.3**
Fossil Fuel Combustion	4,696.6	5,271.8	5,342.4	5,533.7	5,486.9	5,501.8	5,571.1	5,656.6
Non-Energy Use of Fuels	117.2	152.8	160.6	140.7	131.0	136.5	133.5	153.4
Municipal Solid Waste Combustion	10.9	17.1	17.6	17.9	18.6	18.9	19.4	19.4
Natural Gas Flaring	5.8	6.6	6.9	5.8	6.1	6.2	6.1	6.0
Biomass-Wood *	*212.5*	*209.5*	*214.3*	*217.6*	*190.8*	*182.9*	*186.3*	*191.7*
International Bunker Fuels *	*113.5*	*114.6*	*105.2*	*101.4*	*97.8*	*89.5*	*84.1*	*94.5*
Biomass-Ethanol *	*4.2*	*7.7*	*8.0*	*9.2*	*9.7*	*11.5*	*15.8*	*19.5*
CH$_4$	**261.6**	**235.4**	**226.8**	**228.7**	**225.0**	**220.1**	**220.9**	**215.8**
Natural Gas Systems	126.7	125.4	121.7	126.7	125.6	125.4	124.7	118.8
Coal Mining	81.9	62.8	58.9	56.3	55.5	52.5	54.8	56.3
Petroleum Systems	34.4	29.7	28.5	27.8	27.4	26.8	25.9	25.7
Stationary Combustion	7.9	6.8	7.0	7.3	6.6	6.2	6.5	6.4
Abandoned Underground Coal Mines	6.0	6.9	6.9	7.2	6.6	6.0	5.8	5.6
Mobile Combustion	4.7	3.8	3.6	3.5	3.3	3.2	3.0	2.9
International Bunker Fuels *	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N$_2$O	**56.2**	**68.6**	**67.9**	**67.5**	**63.9**	**61.3**	**58.9**	**57.0**
Mobile Combustion	43.5	54.8	54.1	53.1	50.0	47.5	44.8	42.8
Stationary Combustion	12.3	13.4	13.4	13.9	13.5	13.2	13.6	13.7
Municipal Solid Waste Combustion	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.5
International Bunker Fuels *	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.9*
Total	**5,148.3**	**5,752.3**	**5,822.3**	**5,994.3**	**5,931.6**	**5,944.6**	**6,009.8**	**6,108.2**

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 3-2: CO$_2$, CH$_4$, and N$_2$O Emissions from Energy (Gg)

Gas/Source	1990	1998	1999	2000	2001	2002	2003	2004
CO$_2$	**4,830,464**	**5,448,279**	**5,527,589**	**5,698,086**	**5,642,664**	**5,663,284**	**5,730,029**	**5,835,335**
Fossil Fuel Combustion	4,696,571	5,271,819	5,342,446	5,533,710	5,486,908	5,501,763	5,571,088	5,656,554
Non-Energy Use of Fuels	117,168	152,800	160,569	140,687	131,028	136,455	133,489	153,386
Municipal Solid Waste Combustion	10,919	17,094	17,632	17,921	18,634	18,862	19,360	19,360
Natural Gas Flaring	5,805	6,566	6,943	5,769	6,094	6,204	6,091	6,034
Biomass-Wood *	*212,547*	*209,490*	*214,323*	*217,577*	*190,778*	*182,878*	*186,339*	*191,737*
International Bunker Fuels *	*113,503*	*114,557*	*105,228*	*101,366*	*97,815*	*89,489*	*84,083*	*94,499*
Biomass-Ethanol *	*4,155*	*7,711*	*8,017*	*9,188*	*9,701*	*11,473*	*15,771*	*19,493*
CH$_4$	**12,459**	**11,211**	**10,800**	**10,893**	**10,715**	**10,480**	**10,517**	**10,277**
Natural Gas Systems	6,034	5,973	5,797	6,033	5,981	5,971	5,939	5,658
Coal Mining	3,900	2,990	2,807	2,679	2,644	2,500	2,611	2,682
Petroleum Systems	1,640	1,414	1,358	1,325	1,303	1,274	1,236	1,222
Stationary Combustion	374	325	335	346	316	295	311	307
Abandoned Underground Coal Mines	286	328	330	343	313	288	277	269
Mobile Combustion	224	181	173	167	159	152	144	140
International Bunker Fuels *	*8*	*7*	*6*	*6*	*5*	*4*	*4*	*5*
N$_2$O	**181**	**221**	**219**	**218**	**206**	**198**	**190**	**184**
Mobile Combustion	140	177	174	171	161	153	144	138
Stationary Combustion	40	43	43	45	44	43	44	44
Municipal Solid Waste Combustion	2	1	1	1	1	2	2	2
International Bunker Fuels *	*3*	*3*	*3*	*3*	*3*	*3*	*2*	*3*

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Figure 3-2

2004 U.S. Fossil Carbon Flows (Tg CO₂ Eq.)

Fossil Fuel Energy Exports 261

Non-Energy Use Exports 91

Stock Changes 2

Balancing Item 37

International Bunkers 95

Industrial Processes 83

NEU Emissions 22

Coal Emissions 2,027

Combustion Emissions 2,049

NEU Emissions 8

Natural Gas Emissions 1,191

Combustion Emissions 1,199

NEU Emissions 124

Petroleum Emissions 2,438

Combustion Emissions 2,562

Coal 2,126

Natural Gas 1,040

Petroleum 888

Domestic Fossil Fuel Production 4,202

Apparent Consumption 6,328

Atmospheric Emissions 5,988

Natural Gas Liquids, Liquefied Refinery Gas, & Other Liquids 148

Fossil Fuel Energy Imports 2,357

Petroleum 1,860

NG 231

Coal 83

Other 183

Non-Energy Use Imports 60

Fossil Fuel Consumption U.S. Territories 52

Non-Energy Use U.S. Territories 12

Non-Energy Use Carbon Sequestered 250

Fossil Fuel Combustion Residual (Not Oxidized Fraction) 53

Note: Totals may not sum due to independent rounding.
The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams of CO₂ equivalents (Tg CO₂ Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 6,108.2 Tg CO₂ Eq. in 2004, an increase of 19 percent since 1990.

3.1. Carbon Dioxide Emissions from Fossil Fuel Combustion (IPCC Source Category 1A)

CO₂ emissions from fossil fuel combustion in 2004 increased by 1.5 percent from the previous year. This increase is primarily a result of increased demand for fuels due to a growing economy, expanding industrial production, and increased demand for transportation. In 2004, CO₂ emissions from fossil fuel combustion were 5,656.6 Tg CO₂ Eq., or 20 percent above emissions in 1990 (see Table 3-3).[2]

Trends in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer

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[2] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Table 3-3: CO$_2$ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO$_2$ Eq.)

Fuel/Sector	1990	1998	1999	2000	2001	2002	2003	2004
Coal	**1,683.8**	**1,944.0**	**1,946.2**	**2,033.8**	**1,982.5**	**1,976.8**	**2,017.4**	**2,027.0**
Residential	2.9	1.2	1.3	1.0	1.1	1.0	0.9	1.0
Commercial	11.6	9.5	9.6	8.1	8.6	8.6	7.9	8.2
Industrial	151.3	131.1	126.7	127.2	126.1	116.4	117.7	117.1
Transportation	NE	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,517.3	1,801.2	1,807.7	1,896.6	1,845.9	1,849.6	1,887.2	1,897.1
U.S. Territories	0.6	1.0	0.9	0.9	0.9	1.2	3.6	3.6
Natural Gas	**1,006.9**	**1,168.4**	**1,172.2**	**1,220.2**	**1,173.4**	**1,211.4**	**1,184.8**	**1,191.2**
Residential	238.6	246.6	256.4	269.2	259.0	265.6	276.9	265.5
Commercial	142.4	163.6	165.3	171.8	164.9	170.8	175.4	162.7
Industrial	413.2	474.1	453.9	461.7	424.8	431.2	416.1	428.4
Transportation	35.9	35.1	35.6	35.5	33.9	37.1	37.3	37.4
Electricity Generation	176.9	249.1	260.9	281.4	289.5	305.6	277.6	295.8
U.S. Territories	NO	NO	NO	0.7	1.2	1.2	1.4	1.3
Petroleum	**2,005.5**	**2,159.0**	**2,223.7**	**2,279.3**	**2,330.6**	**2,313.2**	**2,368.5**	**2,438.0**
Residential	96.5	85.8	94.6	99.7	101.4	93.3	100.9	103.0
Commercial	68.5	44.6	43.7	49.3	51.4	45.0	52.5	55.1
Industrial	286.7	266.7	268.4	273.7	310.2	294.6	310.8	318.0
Transportation	1,425.5	1,625.2	1,686.8	1,731.4	1,719.7	1,761.7	1,763.8	1,818.1
Electricity Generation	100.9	104.2	96.6	91.0	101.6	77.8	97.0	97.3
U.S. Territories	27.4	32.5	33.6	34.2	46.4	40.7	43.7	46.5
Geothermal*	**0.40**	**0.38**	**0.38**	**0.36**	**0.35**	**0.37**	**0.37**	**0.37**
Total	**4,696.6**	**5,271.8**	**5,342.4**	**5,533.7**	**5,486.9**	**5,501.8**	**5,571.1**	**5,656.6**

NE (Not estimated)
NO (Not occurring)
+ Does not exceed 0.05 Tg CO$_2$ Eq.
* Although not technically a fossil fuel, geothermal energy-related CO$_2$ emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO$_2$ emissions also depend on the source of energy and its carbon intensity. The amount of carbon in fuels varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[3] Producing a unit of heat or electricity using natural gas instead of coal can reduce the CO$_2$ emissions associated with energy consumption, and using nuclear or renewable energy sources (e.g., wind) can essentially eliminate emissions (see Box 3-2). Table 3-4 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

In the United States, 86 percent of the energy consumed in 2004 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (6 percent), primarily hydroelectric power and biofuels (EIA 2005a). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 39 percent of total energy consumption from 1990 through 2004. Natural gas and coal followed in order of importance, accounting for 24 and 23 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector, the vast majority of coal was used in electricity generation, and natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2005a).

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the carbon stored in the fuels is oxidized and emitted as CO$_2$ and smaller amounts of other gases,
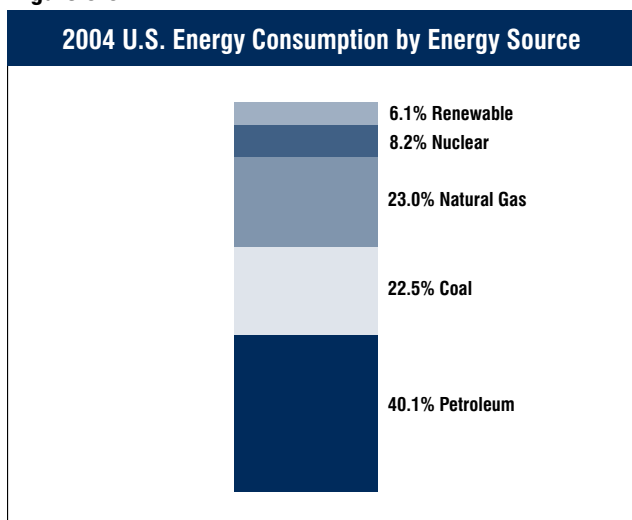
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[3] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Table 3-4: Annual Change in CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2000 to 2001		2001 to 2002		2002 to 2003		2003 to 2004	
Electricity Generation	Coal	-50.7	-3%	3.8	0%	37.5	2%	9.9	1%
Electricity Generation	Natural Gas	8.2	3%	16.1	6%	-28.0	-9%	18.2	7%
Electricity Generation	Petroleum	10.5	12%	-23.7	-23%	19.2	25%	0.3	0%
Transportation[a]	Petroleum	-11.7	-1%	42.0	2%	2.0	0%	54.3	3%
Residential	Natural Gas	-10.2	-4%	6.6	3%	11.4	4%	-11.4	-4%
Commercial	Natural Gas	-6.9	-4%	5.9	4%	4.6	3%	-12.7	-7%
Industrial	Coal	-1.1	-1%	-9.7	-8%	1.4	1%	-0.7	-1%
Industrial	Natural Gas	-36.8	-8%	6.3	1%	-15.0	-3%	12.3	3%
All Sectors[b]	**All Fuels[b]**	**-46.8**	**-1%**	**14.9**	**0%**	**69.3**	**1%**	**85.5**	**2%**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

Figure 3-3

2004 U.S. Energy Consumption by Energy Source

6.1% Renewable
8.2% Nuclear
23.0% Natural Gas
22.5% Coal
40.1% Petroleum

Figure 3-4

U.S. Energy Consumption (Quadrillion Btu)

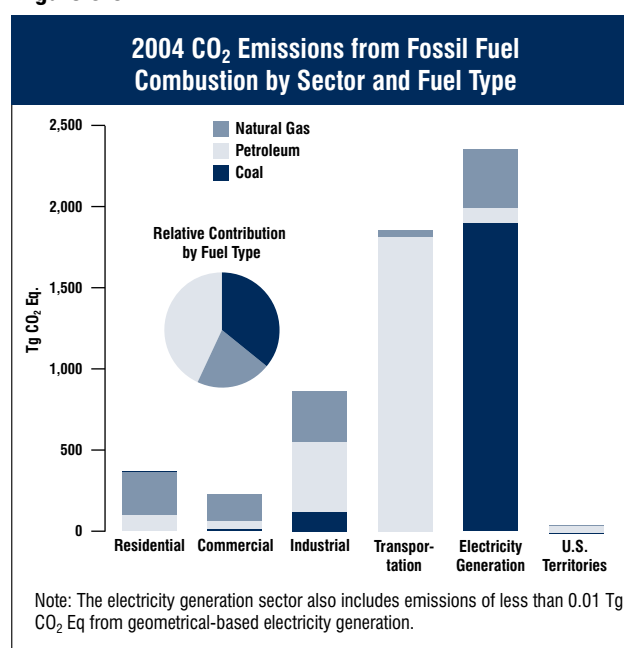Note: Expressed as gross calorific values

including CH_4, CO, and NMVOCs.[4] These other carbon containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, except for the soot and ash left behind during the combustion process, all the carbon in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

For the purpose of international reporting, the Intergovernmental Panel on Climate Change (IPCC) (IPCC/UNEP/OECD/IEA 1997) recommends that particular

Figure 3-5

2004 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.01 Tg CO_2 Eq from geometrical-based electricity generation.

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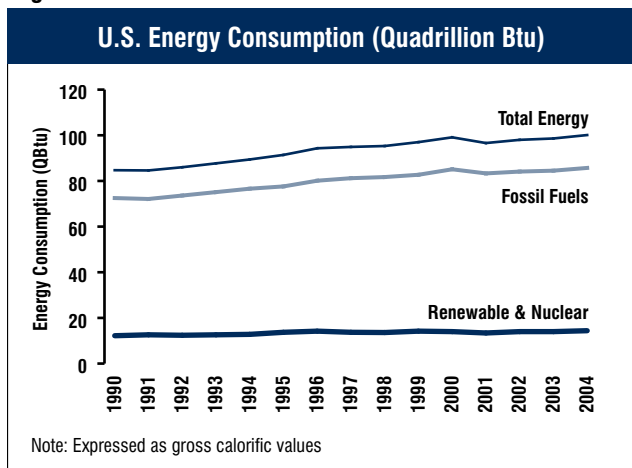
[4] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

Box 3-1: Weather and Non-Fossil Energy Effects on CO$_2$ from Fossil Fuel Combustion Trends

In 2004, weather conditions became milder in both the winter and summer. Warmer winter conditions led to a decrease in demand for heating fuels. Though the summer of 2004 was cooler than the previous year, demand for electricity still increased, likely due to the growing economy. The winter was warmer than usual, with heating degree days in the United States 5 percent below normal (see Figure 3-6). Summer temperatures were slightly warmer than usual, with cooling degree days 1 percent above normal (see Figure 3-7) (EIA 2005f).[5]

Figure 3-6

Annual Deviations from Normal Heating Degree Days for the United States (1950-2004)

Note: Climatological normal data are highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.

Figure 3-7

Annual Deviations from Normal Cooling Degree Days for the United States (1950-2004)

Note: Climatological normal data are highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[6]) of existing plants reached record levels in 2004, at over 90 percent. Electricity output by hydroelectric power plants increased in 2004 by approximately 10 percent. Electricity generated by nuclear plants in 2004 provided almost 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2005a). Aggregate nuclear and hydroelectric power plant capacity factors since 1973 are shown in Figure 3-8.

Figure 3-8

Aggregate Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1974-2004)

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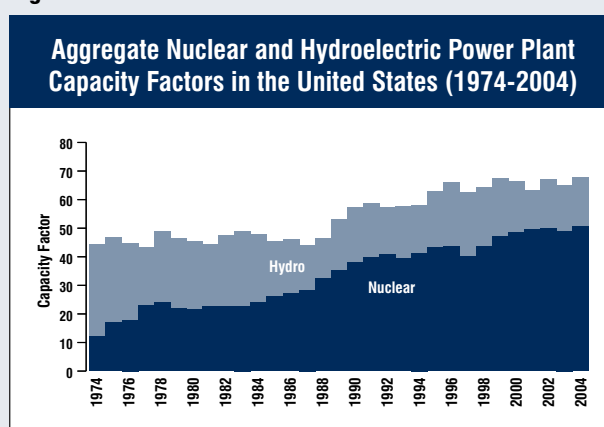
[5] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

[6] The capacity factor is defined as the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period (EIA 2005a).

adjustments be made to national fuel consumption statistics. Certain fossil fuels can be manufactured into plastics, asphalt, lubricants, or other products. A portion of the carbon consumed for these non-energy products can be stored (i.e., sequestered) indefinitely. To account for the fact that the carbon in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), consumption of fuels for non-energy purposes is estimated and subtracted from total fuel consumption estimates. Emissions from non-energy uses of fuels are estimated in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter.

According to the UNFCCC reporting guidelines, CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) should be reported separately, and not included in national emission totals. Estimates of international bunker fuel emissions for the United States are provided in Table 3-5.

End-Use Sector Consumption

An alternative method of presenting CO_2 emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. For the discussion below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption. This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. After the end-use sectors are discussed, emissions from electricity generation are addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 3-6 and

Table 3-5: CO_2 Emissions from International Bunker Fuels (Tg CO_2 Eq.)*

Vehicle Mode	1990	1998	1999	2000	2001	2002	2003	2004
Aviation	46.2	56.7	58.8	60.5	59.3	61.8	59.4	59.9
Marine	67.3	57.9	46.4	40.9	38.5	27.7	24.6	34.6
Total	**113.5**	**114.6**	**105.2**	**101.4**	**97.8**	**89.5**	**84.1**	**94.5**

* See International Bunker Fuels section for additional details.
Note: Totals may not sum due to independent rounding.

Table 3-6: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1998	1999	2000	2001	2002	2003	2004
Transportation	**1,464.4**	**1,663.4**	**1,725.6**	**1,770.3**	**1,757.0**	**1,802.2**	**1,805.4**	**1,860.2**
Combustion	1,461.4	1,660.3	1,722.4	1,766.9	1,753.6	1,798.8	1,801.0	1,855.5
Electricity	3.0	3.1	3.2	3.4	3.5	3.4	4.3	4.7
Industrial	**1,528.3**	**1,634.5**	**1,613.5**	**1,642.8**	**1,574.9**	**1,542.8**	**1,572.4**	**1,595.0**
Combustion	851.1	871.9	849.0	862.6	861.2	842.1	844.6	863.5
Electricity	677.2	762.6	764.5	780.3	713.7	700.7	727.7	731.5
Residential	**922.8**	**1,044.5**	**1,064.0**	**1,123.2**	**1,123.2**	**1,139.8**	**1,166.6**	**1,166.8**
Combustion	338.0	333.5	352.3	369.9	361.5	360.0	378.8	369.6
Electricity	584.8	711.0	711.7	753.3	761.7	779.8	787.9	797.2
Commercial	**753.1**	**895.9**	**904.8**	**961.6**	**983.3**	**973.9**	**978.1**	**983.1**
Combustion	222.6	217.7	218.6	229.3	224.9	224.3	235.8	226.0
Electricity	530.5	678.2	686.2	732.4	758.4	749.6	742.2	757.2
U.S. Territories	**28.0**	**33.5**	**34.5**	**35.8**	**48.5**	**43.1**	**48.7**	**51.4**
Total	**4,696.6**	**5,271.8**	**5,342.4**	**5,533.7**	**5,486.9**	**5,501.8**	**5,571.1**	**5,656.6**
Electricity Generation	**1,795.5**	**2,154.9**	**2,165.6**	**2,269.3**	**2,237.3**	**2,233.5**	**2,262.2**	**2,290.6**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 3-9 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated electricity generation emissions from electricity consumption by end-use sector.

Transportation End-Use Sector

Using this allocation method, the transportation end-use sector accounted for 1,860.2 Tg CO_2 in 2004, or approximately 33 percent of total CO_2 emissions from fossil fuel combustion, the largest share of any end-use economic sector.[7] Between 1990 and 2004, transportation CO_2 emissions increased by 395.8 Tg CO_2, representing approximately 40 percent of the growth in energy-related CO_2 emissions from all sectors. Almost all of the energy consumed in the transportation sector was petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil.

Table 3-7 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. As detailed in the table, overall transportation CO_2 emissions increased by 27 percent from 1990 to 2004, representing an average annual increase of 1.7 percent. Between 2003 and 2004 transportation CO_2 emissions increased by just over 3.0 percent.

Transportation fuel consumption is broadly affected by travel activity and the amount of energy vehicles used to move people and goods by various travel modes. In the short-term, changes transportation energy consumption and

CO_2 emissions primarily reflect variation in travel activity that accompanies year-to-year economic fluctuations. Long-term factors, especially the cost of fuel (see Figure 3-10), can impact travel patterns and vehicle energy efficiency. Since 1990, there has been a significant increase in vehicle miles traveled (VMT) by light-duty trucks, freight trucks, and aircraft. At the same time, the fuel economy of light-duty trucks and freight trucks has remained roughly constant. By contrast, commercial aircraft have become noticeably more fuel efficient.

As shown in Table 3-7, automobiles and light-duty trucks (consuming both gasoline and diesel) accounted for approximately 63 percent of transportation CO_2 emissions in 2004. From 1990 to 2004, carbon dioxide emissions from automobiles and light-duty trucks increased roughly 24 percent (227.7 Tg CO_2). Over this period, VMT by automobile and light-duty trucks increased by 37 percent, outweighing a small increase in overall fleet fuel economy (see Figure 3-11). Much of the small increase in overall fleet fuel economy resulted from the retirement of older, less fuel efficient vehicles.

Carbon dioxide emissions from freight trucks[8] increased by 62 percent (140 Tg) from 1990 to 2004, representing the largest emissions rate increase of any major transportation mode. Fuel economy for the freight truck fleet was relatively constant over this period, while truck VMT increased by 53
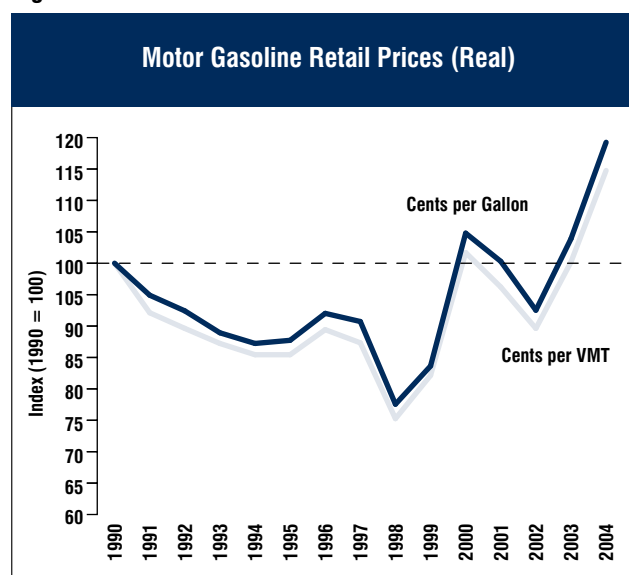
Figure 3-9

2004 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

Figure 3-10

Motor Gasoline Retail Prices (Real)

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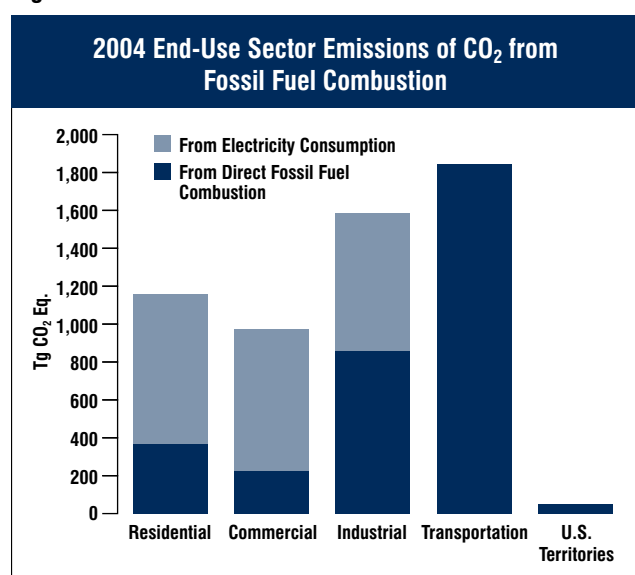
[7] Note that electricity generation is actually the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

[8] Includes "other trucks" fueled by gasoline, diesel and LPG.

percent. Aircraft[9] CO_2 emissions increased by just over one percent (2.3 Tg CO_2) between 1990 and 2004, reflecting a relatively small increase in emissions from commercial aircraft emissions and a decrease in domestic military aircraft emissions. While CO_2 emissions from commercial aircraft grew by approximately 10 percent (11.9 Tg CO_2) from 1990 to 2004, passenger miles traveled increased by 61 percent over the same period, reflecting improvements in the fuel efficiency of planes and an increasing percentage of occupied seats per plane. For further information on all greenhouse

Table 3-7: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.)[a]

Fuel/Vehicle Type	1990	1998	1999	2000	2001	2002	2003	2004
Gasoline	**964.9**	**1,083.7**	**1,111.1**	**1,117.1**	**1,122.1**	**1,149.1**	**1,152.9**	**1,174.3**
Automobiles	611.2	616.0	626.9	629.8	632.9	647.9	627.2	632.2
Light-Duty Trucks	304.0	420.0	436.3	438.4	441.5	453.1	482.7	497.9
Other Trucks	38.1	34.2	34.4	35.4	34.4	34.9	30.0	31.2
Buses	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Motorcycles	1.7	1.8	1.8	1.8	1.7	1.6	1.6	1.7
Boats (Recreational)	9.5	11.3	11.3	11.3	11.3	11.2	11.1	11.1
Distillate Fuel Oil (Diesel)	**270.0**	**364.5**	**382.6**	**397.0**	**397.6**	**411.7**	**418.4**	**443.4**
Automobiles	7.7	5.5	4.3	3.6	3.6	3.7	4.1	4.2
Light-Duty Trucks	11.2	16.8	18.4	19.6	20.3	21.4	26.6	27.8
Other Trucks	186.4	271.7	287.5	302.1	302.1	315.6	316.7	333.6
Buses	7.8	9.2	10.3	10.0	9.1	8.6	9.4	9.3
Locomotives	34.8	39.9	41.4	41.2	41.4	41.8	42.8	45.1
Ships & Boats	10.6	9.8	12.5	14.3	15.8	15.6	12.7	16.3
Ships (Bunkers)	11.4	11.5	8.2	6.2	5.2	5.1	6.0	7.0
Jet Fuel	**220.4**	**235.6**	**242.9**	**251.2**	**240.4**	**234.4**	**229.1**	**237.4**
Commercial Aircraft	117.2	126.3	136.4	140.6	132.8	121.7	122.8	129.1
Military Aircraft	34.8	21.5	20.6	21.0	22.8	20.4	20.5	21.1
General Aviation Aircraft	6.3	7.7	9.2	9.2	9.0	9.3	9.3	9.6
Other Aircraft[b]	15.9	23.4	17.9	19.9	16.4	21.2	17.1	17.6
Aircraft (Bunkers)	46.2	56.7	58.8	60.5	59.3	61.8	59.4	59.9
Aviation Gasoline	**3.1**	**2.4**	**2.7**	**2.5**	**2.4**	**2.3**	**2.1**	**2.1**
General Aviation Aircraft	3.1	2.4	2.7	2.5	2.4	2.3	2.1	2.1
Residual Fuel Oil	**79.3**	**52.6**	**51.9**	**64.2**	**54.2**	**52.8**	**44.5**	**54.6**
Ships & Boats[c]	23.4	6.2	13.7	29.6	21.0	30.2	25.9	27.0
Ships (Bunkers)[c]	55.8	46.4	38.2	34.6	33.2	22.6	18.6	27.6
Natural Gas	**35.9**	**35.1**	**35.6**	**35.5**	**33.9**	**37.1**	**37.3**	**37.4**
Automobiles	+	+	+	+	+	+	+	+
Light Trucks	+	+	+	+	+	+	+	+
Buses	+	0.2	0.3	0.4	0.5	0.6	0.6	0.6
Pipeline	35.9	34.9	35.3	35.0	33.4	36.4	36.7	36.8
LPG	**1.4**	**1.0**	**0.8**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**
Light Trucks	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Other Trucks	0.8	0.6	0.5	0.4	0.5	0.5	0.5	0.5
Buses	+	+	+	+	+	+	+	+
Electricity	**3.0**	**3.1**	**3.2**	**3.4**	**3.5**	**3.4**	**4.3**	**4.7**
Rail	3.0	3.1	3.2	3.4	3.5	3.4	4.3	4.7
Total (Including Bunkers)[d]	**1,577.9**	**1,778.0**	**1,830.8**	**1,871.6**	**1,854.9**	**1,891.7**	**1,889.4**	**1,954.7**
Total (Excluding Bunkers)[d]	**1,464.4**	**1,663.4**	**1,725.6**	**1,770.3**	**1,757.0**	**1,802.2**	**1,805.4**	**1,860.2**

Note: Totals may not sum due to independent rounding.
[a] Emissions are no longer allocated to gasoline and diesel consumption from agriculture and construction, and electricity consumption from pipelines. This is based on recognition that EIA statistics account for these activities in the industrial sector.
[b] This category represents all other jet fuel consumption, and may include some small commercial aircraft and jet fuel used for heating oil.
[c] Fluctuations in emission estimates from the combustion of residual fuel oil are currently unexplained, but may be related to data collection problems.
[d] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.
+ Less than 0.05 Tg CO_2 Eq.

[9] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not accounted for in national emission totals.

Figure 3-11

Personal Vehicle Fuel Economy
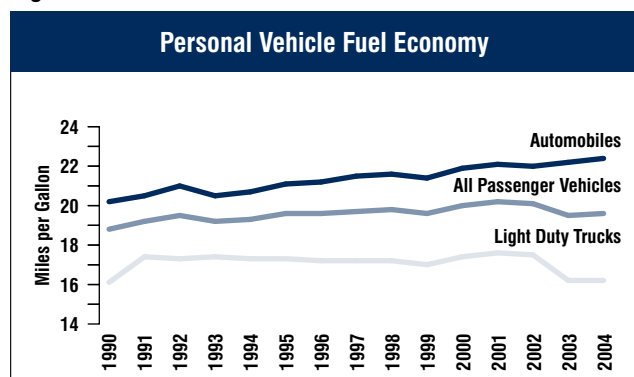
gas emissions from transportation sources, please refer to Table A-104 in Annex 3.2.

Table 3-7 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. Fifty-eight percent of the emissions from this end-use sector in 2004 were the result of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, respectively accounting for 19 and 12 percent of CO_2 emissions from the transportation end-use sector.[10] For information on transportation-related CO_2 emissions from agriculture and construction equipment, other off-road equipment, and recreational vehicles, please refer to Table A-112 in Annex 3.2.

Industrial End-Use Sector

The industrial end-use sector accounted for 28 percent of CO_2 emissions from fossil fuel combustion. On average, 54 percent of these emissions resulted from the direct consumption of fossil fuels for steam and process heat production. The remaining 46 percent was associated with their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.

The industrial end-use sector includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Primary Metals, Paper Food, and

Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2005a and 2005i).

In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption is also affected by weather conditions.[11] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy intensive manufacturing products to less energy intensive products (e.g., from steel to computer equipment) also have a significant affect on industrial emissions.

From 2003 to 2004, total industrial production and manufacturing output increased by 4.1 and 5.0 percent, respectively (FRB 2005). Over this period, output increased for all of the aforementioned industries that comprise the majority of manufacturing energy use—Petroleum Refineries, Chemicals, Primary Metals, Paper, Food, and Nonmetallic Mineral Products (see Figure 3-12).

Figure 3-12

Industrial Production Indexes (Index 1997=100)

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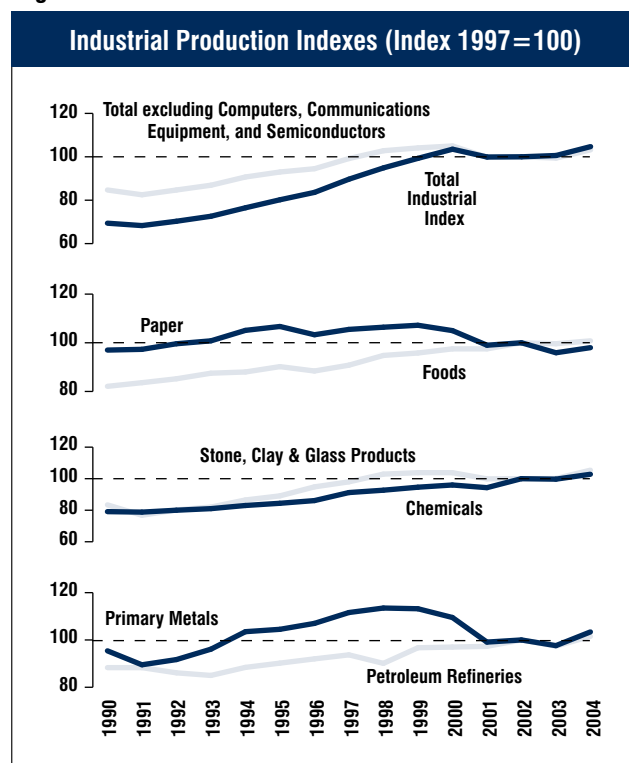
[10] These percentages include emissions from bunker fuels.

[11] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

Despite the growth in industrial output (51 percent) and the overall U.S. economy (51 percent) from 1990 to 2004, CO_2 emissions from the industrial end-use sector increased by only 4 percent. A number of factors are believed to have caused this disparity between rapid growth in industrial output and stagnant growth in industrial emissions are not entirely clear, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, (2) improvements in energy efficiency; and (3) a lowering of the carbon intensity of fossil fuel consumption as industry shifts from its historical reliance on coal and coke to heavier usage of natural gas. In 2004, CO_2 emissions from fossil fuel combustion and electricity use within the industrial end-use sectors were 1,595.0 Tg CO_2 Eq., or 1.4 percent above 2003 emissions.

Residential and Commercial End-Use Sectors

The residential and commercial end-use sectors accounted for an average 21 and 17 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing to about 68 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2004, CO_2 emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,166.8 Tg CO_2 Eq. and 983.1 Tg CO_2 Eq., respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions (see Table 3-6). In the long-term, both end-use sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).
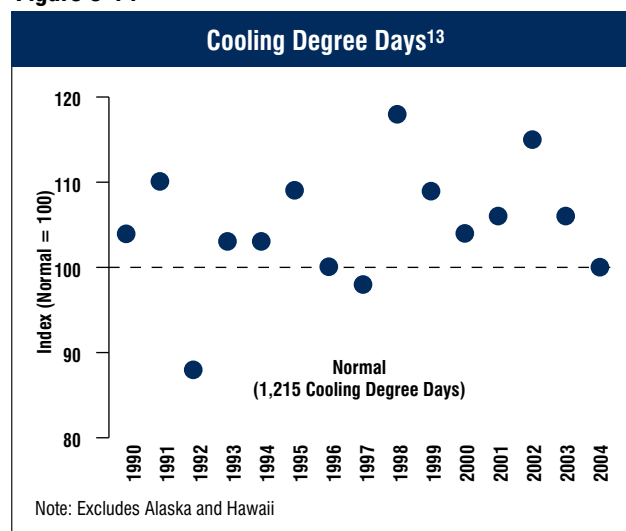
Emissions from natural gas consumption represent over 70 percent of the direct (not including electricity) fossil fuel emissions from the residential and commercial sectors. In 2004, natural gas emissions decreased by 4 and 7 percent, respectively, in each of these sectors, due to warmer conditions in the United States (see Figure 3-13).

Electricity sales to the residential and commercial end-use sectors in 2004 increased by 1.6 and 2.4 percent, respectively. This trend can largely be attributed to the growing economy (4.2 percent), which led to increased demand for electricity.

Figure 3-13

Heating Degree Days[12]

Normal
(4,524 Heating Degree Days)

Index (Normal = 100)

Note: Excludes Alaska and Hawaii

Figure 3-14

Cooling Degree Days[13]

Index (Normal = 100)

Normal
(1,215 Cooling Degree Days)

Note: Excludes Alaska and Hawaii

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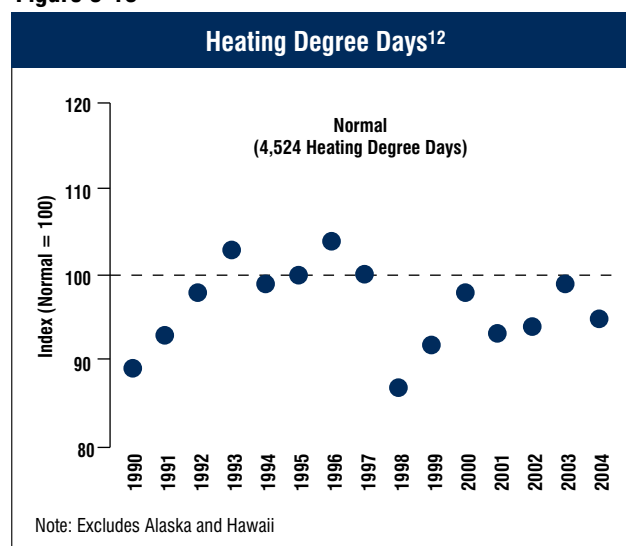
[12] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000.

[13] Degree days are relative measurements of outdoor air temperature. Cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000.

Increased consumption due to these factors was somewhat offset by decreases in air conditioning-related electricity consumption due to the cooler summer (see Figure 3-14). Electricity-related emissions in both the residential and commercial sectors rose due to increased consumption. Total emissions from the residential sector increased by less than 0.1 percent in 2004, with emissions from the commercial sector 0.5 percent higher than in 2003.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 38 percent of total CO_2 emissions from all sources. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-15). Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 40 percent in 2004.

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). The Department of Energy categorizes electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production

of electricity,[14] while the other sectors consist of those producers that indicate their primary business is other than the production of electricity.

In 2004, the amount of electricity generated increased by 1.8 percent, largely due to the growing economy and expanding industrial production. However, CO_2 emissions increased by only 1.3 percent, as a larger share of electricity was generated by nuclear power and natural gas. While coal consumption for electricity generation increased by just 0.5 percent in 2004, natural gas consumption increased by 6.6 percent and nuclear power increased by 3.4 percent. As a result of this shift, carbon intensity from energy consumption for electricity generation decreased in 2004 (see Table 3-9). Coal is consumed primarily by the electric power sector in the United States, which accounted for 94 percent of total coal consumption for energy purposes in 2004. Electricity generation from renewables increased slightly (by 1 percent) in 2004.

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail (EIA 2005b). The United States does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Grillot (2005).[15]

Figure 3-15

Electricity Generation Retail Sales by End-Use Sector

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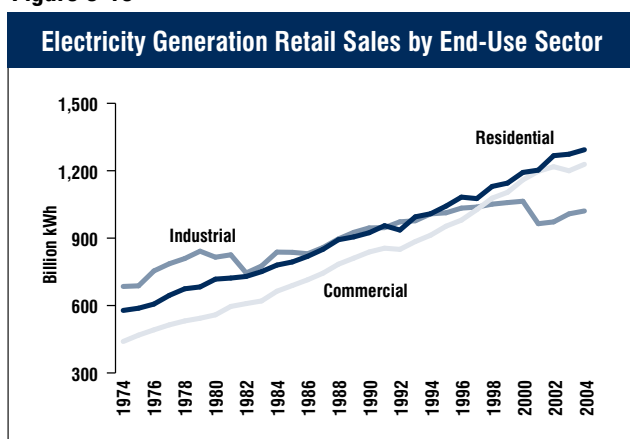
[14] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

[15] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 51 Tg CO_2 Eq. in 2004.

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is emitted as a product from their combustion. Useful energy, however, can be generated from many other sources that do not emit CO_2 in the energy conversion process. In the United States, useful energy is also produced from renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.[16]

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the carbon intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of carbon emitted from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized.[17] Fossil fuels vary in their average carbon content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[18] In general, the carbon content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. Other sources of energy, however, may be directly or indirectly carbon neutral (i.e., 0 Tg CO_2 Eq./Btu). Energy generated from nuclear and many renewable sources does not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be carbon neutral; although these fuels do emit CO_2, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations if the biogenic carbon emitted is offset by the growth of new biomass.[19] The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-8 provides a time series of the carbon intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its energy derived from natural gas for heating. The carbon intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher carbon intensities over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

Table 3-8: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		1998	1999	2000	2001	2002	2003	2004
Residential[a]	57.0		56.3	56.4	56.4	56.6	56.2	56.4	56.5
Commercial[a]	59.2		57.0	56.9	56.9	57.2	56.7	57.0	57.5
Industrial[a]	63.3		62.1	62.2	62.0	62.9	62.4	62.8	62.7
Transportation[a]	70.8		70.6	70.7	70.8	70.8	70.8	70.7	70.8
Electricity Generation[b]	86.0		85.6	85.3	85.1	84.7	84.7	85.4	85.2
U.S. Territories[c]	73.3		56.3	56.4	56.4	56.6	56.2	56.4	56.5
All Sectors[c]	**72.2**		**72.3**	**72.2**	**72.2**	**72.3**	**72.2**	**72.4**	**72.5**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

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[16] Small quantities of CO_2, however, are released from some geologic formations tapped for geothermal energy. These emissions are included with fossil fuel combustion emissions from the electricity generation. Carbon dioxide emissions may also be generated from upstream activities (e.g., manufacture of the equipment) associated with fossil fuel and renewable energy activities, but are not accounted for here.

[17] Generally, more than 97 percent of the carbon in fossil fuel is oxidized to CO_2 with most carbon combustion technologies used in the United States.

[18] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[19] Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

Box 3-2: Carbon Intensity of U.S. Energy Consumption (continued)

In contrast to Table 3-8, Table 3-9 presents carbon intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electricity generation and the end-use sectors in which that electricity was eventually consumed.[20] This table, therefore, provides a more complete picture of the actual carbon intensity of each end-use sector per unit of energy consumed. The transportation end-use sector in Table 3-9 emerges as the most carbon intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass-based fuels such as ethanol. The "other end-use sectors" (i.e., residential, commercial, and industrial) use significant quantities of biofuels such as wood, thereby lowering the overall carbon intensity. The carbon intensity of the electricity generation sector differs greatly from the scenario in Table 3-8, where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit CO_2.

Table 3-9: Carbon Intensity from all Energy Consumption by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		1998	1999	2000	2001	2002	2003	2004
Transportation[a]	70.5		70.2	70.3	70.4	70.3	70.3	70.1	69.9
Other End-Use Sectors[a, b]	57.2		57.4	56.8	57.5	58.1	57.3	57.8	57.7
Electricity Generation[c]	58.5		59.4	58.5	59.5	59.7	58.6	59.3	59.1
All Sectors[d]	**60.8**		**60.9**	**60.6**	**61.0**	**61.5**	**61.0**	**61.3**	**61.2**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Other End-Use Sectors includes the residential, commercial, and industrial sectors.
[c] Includes electricity generation from nuclear and renewable sources.
[d] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

By comparing the values in Table 3-8 and Table 3-9, a few observations can be made. The use of renewable and nuclear energy sources has resulted in a significantly lower carbon intensity of the U.S. economy. Over the fourteen-year period of 1990 through 2004, however, the carbon intensity of U.S. energy consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies have not changed significantly.

The carbon intensity of total energy consumption in the United States has remained fairly constant. Per capita energy consumption has fluctuated, but is now roughly equivalent to levels in 1990 (see Figure 3-16). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990.

Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2005a) and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Figure 3-16

U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

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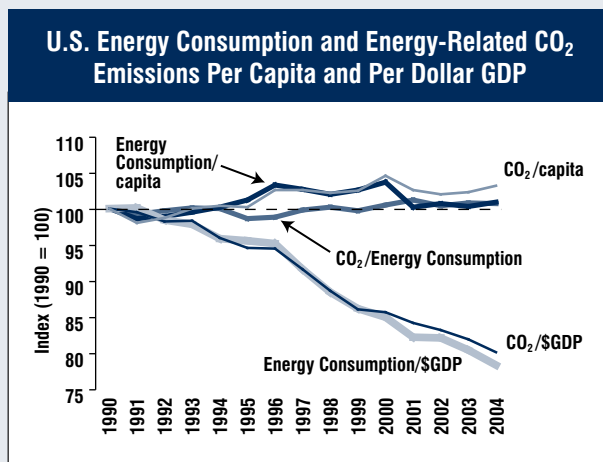
[20] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to electricity generation and the end-use sector in which electricity consumption occurred.

For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.[21]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[22]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for six fuel categories—coking coal, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from Gambogi (2005), EFMA (1995), U.S. Census Bureau (1991 through 1994), U.S. Census Bureau (1998 through 2003), USITC (2005), U.S. Census Bureau (2005), EIA (2005h), EIA (2001b), USAA (2005), USGS (1998 through 2002), USGS (1995), USGS (1995 through 2005), USGS (1991 through 2005), USGS (1991 through 2004), U.S. International Trade Commission (2004a), U.S. International Trade Commission (2004b), Onder and Bagdoyan (1993), and Johnson (2005).[23]

3. *Adjust for biofuels, conversion of fossil fuels, and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude (1) fuels with biogenic origins, (2) fuels created from other fossil fuels, and (3) exports of CO_2. Fuels with biogenic origins are assumed to result in no net CO_2 emissions, and must be subtracted from fuel consumption estimates. These fuels include ethanol added to motor gasoline and biomass gas used as natural gas. Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[24] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol and biogas were collected from EIA (2005b) and data for synthetic natural gas were collected from EIA (2005e), and data for CO_2 exports were collected from the Dakota Gasification Company (2004), Fitzpatrick (2002), Erickson (2003), EIA (2001a), EIA (2002 through 2003), EIA (2005e), and Kass (2005).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on FHWA Vehicle Miles Traveled (VMT) that indicated that the amount of distillate consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel consumption was adjusted higher to match the value obtained from the bottom-up analysis based on VMT. As the total distillate consumption estimate from EIA is considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted

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[21] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[22] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

[23] See sections on Iron and Steel Production, Ammonia Manufacture, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, and Aluminum Production in the Industrial Processes chapter.

[24] These adjustments are explained in greater detail in Annex 2.1.

downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2005), Benson (2002 through 2004), DOE (1993 through 2004), EIA (2005a), EIA (1991 through 2005), EPA (2004b), and FHWA (1996 through 2005).

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, this can result in storage of some or all of the carbon contained in the fuel for a period of time. As the emission pathways of carbon used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2005b).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).[25] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2005) supplied data on military jet fuel use. Commercial jet fuel use was obtained from BEA (1991 through 2005) and DOT (1991 through 2005); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2005). Consumption

of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions are discussed further in the section entitled International Bunker Fuels.

7. *Determine the total carbon content of fuels consumed.* Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel was converted to CO_2. The carbon content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 2004* (EIA 2005c) and EIA's *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail EIA (EIA 2005b). They are presented in Annexes 2.1 and 2.2.

8. *Adjust for carbon that does not oxidize during combustion.* Because most combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot and ash. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process was assumed to be 1 percent for petroleum[26] and coal and 0.5 percent for natural gas (see Annex 2.1). Unoxidized or partially oxidized organic (i.e., carbon containing) combustion products were assumed to have eventually oxidized to CO_2 in the atmosphere.[27] IPCC provided fraction oxidized values for petroleum and natural gas (IPCC/UNEP/OECD/IEA 1997). Bechtel (1993) provided the fraction oxidation value for coal.

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States.[28] For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. For jet fuel, CO_2 emissions were calculated directly based on reported consumption of fuel. For highway

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[25] See International Bunker Fuels section in this chapter for a more detailed discussion.

[26] Based on an analysis of carbon mass balances, it is assumed that 100 percent of carbon is oxidized during combustion in light-duty gasoline cars and trucks.

[27] See Indirect CO_2 from CH_4 Oxidation section in this chapter for a more detailed discussion.

[28] Electricity generation is not considered a final end-use sector, because energy is consumed primarily to provide electricity to the other sectors.

vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2005); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2004). For non-highway vehicles, activity data were obtained from AAR (2005), BEA (1991 through 2005), Benson (2002 through 2004), DOE (1993 through 2004), DESC (2005), DOC (1991 through 2005), DOT (1991 through 2005), EIA (2002a), EIA (2002b), EIA (2005a), EIA (2005d), EIA (2005g), EIA (1991 through 2005), EPA (2004), and FAA (2005). Heat contents and densities were obtained from EIA (2005a) and USAF (1998).[29] The difference between total U.S. jet fuel consumption (as reported by EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT and BEA) plus military jet fuel consumption is reported as "other" under the jet fuel category in Table 3-7, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuels used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2004. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with Carbon emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use

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[29] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

sector emissions. In particular, residual fuel consumption data for marine vessels are highly uncertain, as shown by the large fluctuations in emissions that do not mimic changes in other variables such as shipping ton miles.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant inventory variables from the inventory estimation

model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 150 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[30] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The

Table 3-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

| Fuel/Sector | 2004 Emission Estimate (Tg CO_2 Eq.) | Uncertainty Range Relative to Emission Estimate[a] | | | |
| | | (Tg CO_2 Eq.) | | (%) | |
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal[b]	**2,027.0**	**1,974.8**	**2,232.2**	**-3%**	**+10%**
Residential	1.0	1.0	1.2	-5%	+16%
Commercial	8.2	7.8	9.5	-4%	+16%
Industrial	117.1	113.3	137.2	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,897.1	1,836.0	2,092.8	-3%	+10%
U.S. Territories	3.6	3.2	4.3	-12%	+20%
Natural Gas[b]	**1,191.2**	**1,204.8**	**1,274.9**	**1%**	**+7%**
Residential	265.5	258.9	285.1	-3%	+7%
Commercial	162.7	158.7	174.7	-2%	+7%
Industrial	428.4	439.5	483.9	3%	+13%
Transportation	37.4	36.5	40.1	-2%	+7%
Electricity Generation	295.8	288.3	311.9	-3%	+5%
U.S. Territories	1.3	1.1	1.5	-12%	+17%
Petroleum[b]	**2,438.0**	**2,310.9**	**2,588.6**	**-5%**	**+6%**
Residential	103.0	98.2	108.7	-5%	+5%
Commercial	55.1	52.8	57.7	-4%	+5%
Industrial	318.0	271.3	377.0	-15%	+19%
Transportation	1,818.1	1,703.0	1,944.5	-6%	+7%
Electric Utilities	97.3	93.8	102.3	-4%	+5%
U.S. Territories	46.5	43.3	52.0	-7%	+12%
Total (excluding Geothermal)[b]	**5,656.2**	**5,589.1**	**5,990.1**	**-1%**	**+6%**
Geothermal	**0.4**	**NE**	**NE**	**NE**	**NE**
Total (including Geothermal)[b,c]	**5,656.6**	**5,589.5**	**5,990.5**	**-1%**	**+6%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

[30] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency-personnel.[31]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[32] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-10. Fossil fuel combustion CO_2 emissions in 2004 were estimated to be between 5,589.5 and 5,990.5 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 1 percent below to 6 percent above the 2004 emission estimate of 5,656.6 Tg CO_2 Eq.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The most significant change affecting fuel combustion estimates this year was to correct an error that resulted in emissions to be estimated from some fuels that were either exported or used in industrial processes. A portion of industrial sector fuels are exported as petrochemical feedstocks or used in industrial processes, and are subtracted from the estimated fuel consumed for non-energy use purposes, reported in Section 3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels. However, these fuels had not been subtracted from fuels consumed for energy purposes, resulting in an overestimate of emissions from the industrial sector.

Energy consumption of coking coal and industrial other coal were adjusted due to revised consumption data for metallurgical coke used in the production of iron and steel, and new consumption data for metallurgical coal used the production of lead and zinc. The amount of coking coal used to manufacture the coke used in these processes is estimated based on the amount of coke produced. These coal consumption data are then subtracted from energy consumption estimates, as emissions from the production of iron and steel, lead, and zinc are estimated in the Industrial Processes chapter.

The oxidation factor for motor gasoline used in light-duty vehicles has been changed to 1.00 from the IPCC default factor for petroleum of 0.99. An analysis of carbon mass balances for light-duty gasoline cars and trucks was conducted to assess the proper oxidation factor. The results suggested that the amount of unoxidized carbon is insignificant compared to the gaseous carbon fraction, and that 1.00 should be used to represent the oxidized carbon fraction in future inventories for gasoline fueled light-duty vehicles.

The Energy Information Administration (EIA 2005b) updated energy consumption data for all years. These revisions primarily impacted the emission estimates for 2003. EIA (2005b) now reports a small amount of consumption of other liquids in the electricity generation sector. This fuel type is similar to the composition of jet fuel.

Overall, changes resulted in an average annual decrease of 42.9 Tg CO_2 Eq. (0.8 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2003.

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[31] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[32] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Planned Improvements

Several items are being evaluated to improve the estimates of CO_2 emissions from fossil fuel combustion and to reduce uncertainty:

- The carbon oxidation factor for diesel fuel consumed in highway vehicles may be assessed to determine whether the IPCC default of 0.99 is appropriate, or whether a more representative factor can be determined.

- Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data.

These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU). These fuels are used in the industrial and transportation end-use sectors and are quite diverse, including natural gas, liquid petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal coke (manufactured from coking coal). The non-energy fuel uses are equally diverse, and include application as solvents, lubricants, and waxes, or as raw materials in the manufacture of plastics, rubber, synthetic fibers and other materials.

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 62 percent of the total carbon consumed for non-energy purposes is stored in products, and not released to the atmosphere; the remaining 38 percent is emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted; these emissions are reported separately within the Energy chapter in the Municipal Solid Waste Combustion source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and these affect the mass of carbon in non-energy applications.

As shown in Table 3-11, fossil fuel emissions in 2004 from the non-energy uses of fossil fuels were 153.5 Tg CO_2 Eq., which constituted approximately 3 percent of overall fossil fuel emissions, approximately the same proportion as in 1990. In 2004, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,684 TBtu, an increase of 27 percent since 1990 (see Table 3-12). About 68.2 Tg of the C (250.1 Tg CO_2 Eq.) in these fuels was stored, while the remaining 41.8 Tg C (153.5 Tg CO_2 Eq.) was emitted. The proportion of C emitted as CO_2 has remained about constant since 1990, at about 31 to 37 percent of total non-energy consumption (see Table 3-13).

Methodology

The first step in estimating carbon stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The carbon content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific carbon content values. Both the non-energy fuel consumption and carbon content data were supplied by the EIA (2004) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-12 and Table 3-13, have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[33]

For the remaining non-energy uses, the amount of C stored was estimated by multiplying the potential emissions

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[33] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, and Aluminum Production.

Table 3-11: CO$_2$ Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO$_2$ Eq.)

Year	1990	1998	1999	2000	2001	2002	2003	2004
Potential Emissions	312.9	390.5	415.1	385.5	364.8	371.6	361.2	403.6
Carbon Stored	195.7	237.7	254.6	244.8	233.8	235.1	227.7	250.0
Emissions	**117.2**	**152.8**	**160.6**	**140.7**	**131.0**	**136.5**	**133.5**	**153.4**

Table 3-12: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	1998	1999	2000	2001	2002	2003	2004
Industry	**4,223.4**	**5,354.4**	**5,652.1**	**5,260.5**	**5,044.9**	**5,086.5**	**4,922.6**	**5,371.1**
Industrial Coking Coal	0.0	8.5	45.7	62.7	25.5	46.4	72.0	214.3
Industrial Other Coal	8.2	10.4	11.1	12.4	11.3	12.0	11.9	11.9
Natural Gas to Chemical Plants, Other Uses	278.0	407.9	419.4	421.5	410.6	405.9	389.6	380.1
Asphalt & Road Oil	1,170.2	1,262.6	1,324.4	1,275.7	1,256.9	1,240.0	1,219.5	1,303.9
LPG	1,117.7	1,678.9	1,755.1	1,603.3	1,537.1	1,564.5	1,439.0	1,437.5
Lubricants	186.3	190.8	192.8	189.9	174.0	171.9	159.0	161.0
Pentanes Plus	77.3	197.2	252.8	228.6	199.6	166.0	158.4	156.5
Naphtha (<401° F)	325.3	563.6	485.3	592.3	488.9	563.9	573.9	688.2
Other Oil (>401° F)	676.5	637.8	658.6	553.9	525.2	469.5	515.0	561.7
Still Gas	21.3	0.0	16.1	12.6	35.8	57.8	59.0	63.5
Petroleum Coke	83.6	119.8	189.0	49.4	129.4	111.2	80.8	189.4
Special Naphtha	100.8	103.9	141.0	94.3	77.8	99.4	75.8	47.2
Distillate Fuel Oil	7.0	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Waxes	33.3	42.4	37.4	33.1	36.3	32.2	31.0	30.8
Miscellaneous Products	137.8	119.0	111.9	119.2	124.9	134.2	126.0	113.4
Transportation	**176.0**	**180.2**	**182.1**	**179.4**	**164.3**	**162.4**	**150.1**	**152.1**
Lubricants	176.0	180.2	182.1	179.4	164.3	162.4	150.1	152.1
U.S. Territories	**86.7**	**137.9**	**143.8**	**165.5**	**80.3**	**138.7**	**146.6**	**156.3**
Lubricants	0.7	1.3	1.4	16.4	+	1.5	1.6	1.7
Other Petroleum (Misc. Prod.)	86.0	136.6	142.4	149.1	80.3	137.2	145.0	154.6
Total	**4,486.1**	**5,672.5**	**5,977.9**	**5,605.3**	**5,289.5**	**5,387.6**	**5,219.3**	**5,679.5**

+ Does not exceed 0.05 TBtu
Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in carbon black production, which is also reported in the Industrial Processes chapter.
Note: Totals may not sum due to independent rounding.

by a storage factor. For several fuel types—petrochemical feedstocks (natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Municipal Solid Waste Combustion source category, the storage factors do not account for losses at the disposal end of the life cycle. For industrial coking coal and distillate fuel oil, storage factors were taken from the *Revised IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), which in turn draws from Marland and Rotty (1984). For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of carbon in the respective NEU products.

Table 3-13: 2004 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Consumption (TBtu)	Carbon Content (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO$_2$ Eq.)
Industry	**5,371.1**	**103.8**	–	**67.5**	**36.2**	**132.8**
Industrial Coking Coal	214.3	6.6	0.10	0.7	6.0	21.9
Industrial Other Coal	11.9	0.3	0.62	0.2	0.1	0.4
Natural Gas to Chemical Plants	380.1	5.5	0.62	3.4	2.1	7.6
Asphalt & Road Oil	1,303.9	26.9	1.00	26.9	0.0	0.0
LPG	1,437.5	24.2	0.62	15.1	9.1	33.2
Lubricants	161.0	3.3	0.09	0.3	3.0	10.8
Pentanes Plus	156.5	2.9	0.62	1.8	1.1	3.9
Naphtha (<401° F)	688.2	12.5	0.62	7.8	4.7	17.2
Other Oil (>401° F)	561.7	11.2	0.62	7.0	4.2	15.4
Still Gas	63.5	1.1	0.62	0.7	0.4	1.5
Petroleum Coke	189.4	5.3	0.50	2.6	2.6	9.7
Special Naphtha	47.2	0.9	0.62	0.6	0.4	1.3
Distillate Fuel Oil	11.7	0.2	0.50	0.1	0.1	0.4
Waxes	30.8	0.6	0.58	0.4	0.3	0.9
Miscellaneous Products	113.4	2.3	0.00	0.0	2.3	8.5
Transportation	**152.1**	**3.1**	–	**0.3**	**2.8**	**10.2**
Lubricants	152.1	3.1	0.09	0.3	2.8	10.2
U.S. Territories	**156.3**	**3.1**	–	**0.3**	**2.8**	**10.3**
Lubricants	1.7	0.0	0.09	0.0	0.0	0.1
Other Petroleum (Misc. Prod.)	154.6	3.1	0.10	0.3	2.78	10.2
Total	**5,679.5**	**110.0**	–	**68.1**	**41.8**	**153.4**

+ Does not exceed 0.05 Tg C or 0.05 Tg CO$_2$ Eq.
a To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in carbon black production, which is also reported in the Industrial Processes chapter.
- Not applicable.
Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions (see Table 3-11). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including volatile organic compound, solvent, and non-combustion carbon monoxide emissions, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and energy recovery. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA's compilations of air emission factors (EPA 1995, 2001), *National Air Quality and Emissions Trends Report* data (EPA 2005), *Toxics Release Inventory,* *1998* (2000a), *Biennial Reporting System* data (EPA 2004), pesticide sales and use estimates (EPA 1998, 1999, 2002) and hazardous waste data (EPA 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001b, 2005); the National Petrochemical & Refiners Association (NPRA 2001); the National Asphalt Pavement Association (Connolly 2000); the Emissions Inventory Improvement Program (EIIP 1998, 1999); the U.S. Bureau of the Census (1999, 2003, 2004); the American Plastics Council (APC 2000, 2001, 2003, 2005; Eldredge-Roebuck 2000); the Society of the Plastics Industry (SPI 2000); the Rubber Manufacturers' Association (RMA 2002; STMC 2003); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001; FEB 2005); the *Material Safety Data Sheets* (Miller 1999); the Chemical Manufacturer's Association (CMA 1999); and the American Chemistry Council (ACC 2004.) Specific data sources are listed in full detail in Annex 2.3.

Table 3-14: Tier 2 Quantitative Uncertainty Estimates for CO$_2$ Emissions from Non-Energy Uses of Fossil Fuels (Tg CO$_2$ Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO$_2$ Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO$_2$ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO$_2$	80.6	65.3	96.7	-19%	+20%
Asphalt	CO$_2$	0.0	NA	NA	NA	NA
Lubricants	CO$_2$	21.2	17.6	24.4	-17%	+15%
Waxes	CO$_2$	0.9	0.7	1.5	-24%	+56%
Other	CO$_2$	50.7	22.3	56.8	-56%	+12%
Total	**CO$_2$**	**153.4**	**122.7**	**165.7**	**-20%**	**+8%**

[a]Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-15: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2004 Storage Factor (%)	Uncertainty Range Relative to Inventory Factor[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO$_2$	62%	60%	64%	-3%	+4%
Asphalt	CO$_2$	100%	99%	100%	-1%	+0%
Lubricants	CO$_2$	9%	4%	18%	-58%	+91%
Waxes	CO$_2$	58%	44%	69%	-24%	+19%
Other	CO$_2$	28%	21%	68%	-25%	+141%

[a]Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Uncertainty

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-14 (emissions) and Table 3-15 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2004 was estimated to be between 112.8 and 153.7 Tg CO$_2$ Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 20 percent below to 8 percent above the 2004 emission estimate of 141.7 Tg CO$_2$ Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

In Table 3-15, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil carbon. Emission and storage totals for the different subcategories were compared, and trends across the time series were carefully analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

Recalculations Discussion

This year's methodology reflects several refinements and improvements. The methodology for calculating emissions and storage for feedstocks has been revised in several ways. First, some disparities in data for production and consumption were reconciled. Production data relates only to production within the country; consumption data incorporates information on imports and exports as well as production. Because many commodities are emissive in their use, but not necessarily their production, consumption data is appropriately used in calculations for emissive fates. For purposes of developing an overall mass balance on U.S. non-energy uses of carbon, for those materials that are non-emissive (e.g., plastics), production data is most applicable. And for purposes of adjusting the mass balance to incorporate carbon flows associated with imports and exports, it was necessary to carefully review whether the mass balance already incorporated cross-boundary flows (through the use of consumption data) or not, and to adjust the import/export balance accordingly. This year's effort included a more thorough review of the system boundaries on the mass balance, addressing the use of production and consumption data sets and making corresponding adjustments to the import / export calculations.

In an attempt to account for make the mass balance for petrochemical feedstocks more comprehensive, three additional NEU fates were incorporated into the calculations: antifreeze and deicers, food additives, and silicone rubber. Ethylene, diethylene, and propylene glycol are used in antifreeze and aircraft deicing solutions and generally have emissive fates; their consumption was tallied and added to the emissive side of the mass balance ledger. Many food additives such as acetic acid, maleic anhydride, adipic acid, cresylic acid, triethylene glycol, propylene glycol, dipropylene glycol, glycerin, propionic acid, and benzoic acid, are synthetic, i.e., derived from fossil sources. These are generally metabolized to CO_2, and thus were also counted as emissive uses. On the non-emissive side, silicone rubber is now reflected in the calculations. The results for petrochemicals reflect the additions of these new categories in the attempt to "close" the mass balance for fossil carbon. Compared to other fate categories, the mass of carbon in these three newly added components is small, comprising an average of 1.1 percent of annual carbon flows since 1990.

In another change, one of the emissive fates—refinery wastewaters—was dropped from the mass balance. This change was precipitated by better information on the boundaries for the EIA NEU data set used as the basis for the analysis. Although a small amount of carbon is emitted

through refinery wastewater treatment, it is unlikely that this carbon ever enters the NEU system.

Finally, there have been several updates to the data used to calculate storage factors, not only by adding information for 2004 (where available) but also for updating data sets for earlier years. For example, the results reflect new data for energy recovery (through 2002), cleansers, and imports and exports. Overall, changes resulted in an average annual increase in CO_2 emissions from non-energy use of fuels of 15.2 Tg CO_2 Eq. (13 percent) for the period 1990 through 2003.

Planned Improvements

There are several improvements planned for the future:

- Collecting additional information on energy recovery from Manufacturing Energy Consumption Surveys. An effort is planned to carefully examine the "microdata" from these surveys to determine the nature and quantity of materials initially identified as being destined for "non-energy use" that are actually combusted for energy recovery.

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.

- Better characterizing flows of fossil carbon. Additional "fates" may be researched, including the fossil carbon load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for the remaining fuels (petroleum coke, miscellaneous products, and other petroleum). Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3.

3.3. Stationary Combustion (excluding CO_2) (IPCC Source Category 1A)

Stationary combustion encompasses all fuel combustion activities from fixed sources (versus mobile combustion). Other than CO_2, which was addressed in the previous section, gases from stationary combustion include the greenhouse gases CH_4 and N_2O and the indirect greenhouse gases NO_x, CO, and NMVOCs.[34] Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices.

N_2O and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up, shutdown, and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). CH_4 and NMVOC emissions from stationary combustion are primarily a function of the CH_4 and NMVOC content of the fuel and combustion efficiency.

Emissions of CH_4 decreased 18 percent overall to 6.4 Tg CO_2 Eq. (307 Gg) in 2004. This decrease in CH_4 emissions was primarily due to lower wood consumption in the residential sector. Conversely, N_2O emissions rose 11 percent since 1990 to 13.7 Tg CO_2 Eq. (44 Gg) in 2004. The largest source of N_2O emissions was coal combustion by electricity generators, which alone accounted for 64 percent of total N_2O emissions from stationary combustion in 2004. Overall, however, stationary combustion is a small source of CH_4 and N_2O in the United States.

In contrast, stationary combustion is a significant source of NO_x emissions, though a smaller source of CO and NMVOCs. In 2004, emissions of NO_x from stationary combustion represented 39 percent of national

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[34] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

Table 3-16: CH$_4$ Emissions from Stationary Combustion (Tg CO$_2$ Eq.)

Sector/Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004
Electric Power	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	0.1	0.1	0.1	0.1	+	0.1	0.1
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**2.1**	**2.3**	**2.2**	**2.2**	**2.1**	**2.0**	**2.0**	**2.1**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.8	0.9	0.9	0.9	0.8	0.8	0.8	0.8
Wood	0.9	1.0	1.0	1.0	0.9	0.8	0.8	0.9
Commercial	**0.7**	**0.8**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.2	0.1	0.2	0.2
Natural gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Residential	**4.4**	**3.1**	**3.3**	**3.5**	**3.1**	**2.7**	**3.0**	**2.9**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wood	3.5	2.3	2.5	2.6	2.2	1.9	2.1	2.0
U.S. Territories	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**7.9**	**6.8**	**7.0**	**7.3**	**6.6**	**6.2**	**6.5**	**6.4**

+ Does not exceed 0.05 Tg CO$_2$ Eq.
Note: Totals may not sum due to independent rounding.

Table 3-17: N$_2$O Emissions from Stationary Combustion (Tg CO$_2$ Eq.)

Sector/Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004
Electric Power	**7.6**	**8.9**	**8.9**	**9.3**	**9.1**	**9.1**	**9.3**	**9.4**
Coal	7.1	8.4	8.4	8.8	8.6	8.6	8.8	8.8
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2
Industrial	**3.2**	**3.2**	**3.2**	**3.3**	**3.1**	**2.9**	**2.9**	**3.0**
Coal	0.7	0.6	0.6	0.6	0.6	0.5	0.6	0.6
Fuel Oil	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.5
Natural Gas	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.9	1.9	1.7	1.6	1.6	1.7
Commercial	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	+	0.1	0.1	0.1	+	+	+	+
Residential	**1.1**	**0.8**	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.8**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1
Wood	0.7	0.5	0.5	0.5	0.4	0.4	0.4	0.4
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**12.3**	**13.4**	**13.4**	**13.9**	**13.5**	**13.2**	**13.6**	**13.7**

+ Does not exceed 0.05 Tg CO$_2$ Eq.
Note: Totals may not sum due to independent rounding.

Table 3-18: CH$_4$ Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004
Electric Power	**27**	**31**	**31**	**32**	**32**	**32**	**33**	**33**
Coal	16	19	19	20	20	20	20	20
Fuel Oil	4	4	3	3	4	2	3	3
Natural Gas	3	4	5	5	5	5	5	5
Wood	4	4	4	4	4	4	5	5
Industrial	**101**	**107**	**106**	**107**	**99**	**97**	**95**	**98**
Coal	16	14	14	14	14	13	13	13
Fuel Oil	6	5	5	5	6	5	6	6
Natural Gas	37	43	41	42	38	39	37	39
Wood	41	46	46	47	41	40	39	41
Commercial	**35**	**36**	**37**	**38**	**34**	**34**	**35**	**35**
Coal	1	1	1	1	1	1	1	1
Fuel Oil	10	6	6	7	7	6	7	8
Natural Gas	13	15	15	15	15	15	16	15
Wood	11	14	15	15	12	11	11	12
Residential	**210**	**149**	**159**	**165**	**147**	**130**	**145**	**137**
Coal	9	4	4	3	3	3	3	3
Fuel Oil	14	12	14	15	15	14	15	15
Natural Gas	21	22	23	24	23	24	25	24
Wood	166	110	118	123	105	89	102	95
U.S. Territories	**2**	**2**	**2**	**2**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	2	2	2	2	3	3	3	3
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**374**	**325**	**335**	**346**	**316**	**295**	**311**	**307**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 3-19: N$_2$O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004
Electricity Generation	**24**	**29**	**29**	**30**	**29**	**29**	**30**	**30**
Coal	23	27	27	28	28	28	28	28
Fuel Oil	1	1	1	1	1	+	1	1
Natural Gas	+	+	+	1	1	1	+	1
Wood	+	1	1	1	+	1	1	1
Industrial	**10**	**10**	**10**	**11**	**10**	**9**	**9**	**10**
Coal	2	2	2	2	2	2	2	2
Fuel Oil	2	1	1	2	2	2	2	2
Natural Gas	1	1	1	1	1	1	1	1
Wood	5	6	6	6	5	5	5	6
Commercial	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Residential	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	+	+
Wood	2	1	2	2	1	1	1	1
U.S. Territories	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**40**	**43**	**43**	**45**	**44**	**43**	**44**	**44**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 3-20: NO$_x$, CO, and NMVOC Emissions from Stationary Combustion in 2004 (Gg)

Sector/Fuel Type	NO$_x$	CO	NMVOC
Electric Generation	**3,393**	**451**	**45**
Coal	2,886	226	21
Fuel Oil	113	28	4
Natural gas	252	95	10
Wood	NA	NA	NA
Other Fuels[a]	28	33	1
Internal Combustion	114	69	9
Industrial	**2,610**	**1,303**	**155**
Coal	541	143	10
Fuel Oil	160	52	8
Natural gas	955	419	53
Wood	NA	NA	NA
Other Fuels[a]	121	368	29
Internal Combustion	833	320	55
Commercial/Institutional	**243**	**124**	**16**
Coal	19	11	1
Fuel Oil	49	14	3
Natural gas	154	68	12
Wood	NA	NA	NA
Other Fuels[a]	21	31	9
Residential	**416**	**2,142**	**697**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	20	1,961	675
Other Fuels	396	181	23
Total	**6,662**	**4,020**	**922**

NA (Not Available)

[a] Includes LPG, waste oil, coke oven gas, and coke (EPA 2003, EPA 2005).

[b] Residential coal, fuel oil, and natural gas emissions are included in "Other Fuels" (EPA 2003, EPA 2005).

Note: Totals may not sum due to independent rounding. See Annex 3.1 for emissions in 1990 through 2004.

NO$_x$ emissions, while CO and NMVOC emissions from stationary combustion contributed approximately 5 and 7 percent, respectively, to the national totals. From 1990 to 2004, emissions of NO$_x$ and CO from stationary combustion decreased by 33 and 20 percent, respectively, and emissions of NMVOCs increased by 1 percent.

The decrease in NO$_x$ emissions from 1990 to 2004 are mainly due to decreased emissions from electric power. The decrease in CO and increase in NMVOC emissions over this time period can largely be attributed to apparent changes in residential wood use, which is the most significant source of these pollutants from stationary combustion. Table 3-16 through Table 3-19 provide CH$_4$ and N$_2$O emission estimates from stationary combustion by sector and fuel type. Estimates of NO$_x$, CO, and NMVOC emissions in 2004 are given in Table 3-20.[35]

Methodology

CH$_4$ and N$_2$O emissions were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electric power, and U.S. territories. For the CH$_4$ and N$_2$O estimates, fuel consumption data for the United States were obtained from EIA's *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail (EIA 2005). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Grillot (2005).[36] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[37] Construction and agricultural fuel use was obtained from EPA (2004). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

Emission estimates for NO$_x$, CO, and NMVOCs in this section were obtained from preliminary data (EPA 2005) and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The major categories included in this section

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[35] See Annex 3.1 for a complete time series of indirect greenhouse gas emission estimates for 1990 through 2004.

[36] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH$_4$ and N$_2$O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[37] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

are those reported in EPA (2003) and EPA (2005): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., industrial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The overall emission control efficiency of a source category was derived from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion, as described above, is consistent with the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. A total of 115 input variables were simulated for the uncertainty analysis of this source category (85 from the CO_2 emissions from fossil fuel combustion inventory estimation model and 30 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[38] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[39] However, the CH_4 emission factors differ from those used by EIA. Since these factors were

Table 3-21: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	6.4	4.7	12.5	-26%	+94%
Stationary Combustion	N_2O	13.7	10.4	39.4	-24%	+188%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

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[38] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[39] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC *Good Practice Guidance*, 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-21. Stationary combustion CH_4 emissions in 2004 (*including* biomass) were estimated to be between 4.7 and 12.5 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 26 percent below to 94 percent above the 2004 emission estimate of 6.4 Tg CO_2 Eq.[40] Stationary combustion N_2O emissions in 2004 (*including* biomass) were estimated to be between 10.4 and 39.4 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 24 percent below to 188 percent above the 2004 emissions estimate of 13.7 Tg CO_2 Eq.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to several changes.

Slight changes to emission estimates for sectors are due to revised data from EIA (2005). This revision is explained in greater detail in the section on CO_2 Emissions from Fossil Fuel Combustion within this sector. The combination of the methodological and historical data changes resulted in an average annual decrease of 0.1 Tg CO_2 Eq. (0.8 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.1 Tg CO_2 Eq. (0.4 percent) in N_2O emissions from stationary combustion for the period 1990 through 2003.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary source combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated. Currently, the exclusion of biomass increases the uncertainty, although it was expected to reduce the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

3.4. Mobile Combustion (excluding CO_2) (IPCC Source Category 1A)

Mobile combustion emits greenhouse gases other than CO_2, including CH_4, N_2O, and the indirect greenhouse gases NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, as well as usage of pollution control equipment. N_2O, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in

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[40] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Table 3-22: CH$_4$ Emissions from Mobile Combustion (Tg CO$_2$ Eq.)

Fuel Type/Vehicle Type[a]	1990	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	**4.2**	**3.3**	**3.0**	**2.9**	**2.7**	**2.5**	**2.3**	**2.2**
Passenger Cars	2.6	1.8	1.7	1.6	1.5	1.4	1.3	1.3
Light-Duty Trucks	1.4	1.3	1.2	1.1	1.0	1.0	0.9	0.9
Heavy-Duty Vehicles	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	+	+	+	+	+	+	+	+
Alternative Fuel Highway	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Highway	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**
Ships and Boats	0.1	+	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Farm Equipment	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Construction Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other[b]	+	+	+	+	+	0.1	0.1	0.1
Total	**4.7**	**3.8**	**3.6**	**3.5**	**3.3**	**3.2**	**3.0**	**2.9**

+ Less than 0.05 Tg CO$_2$ Eq.
Note: Totals may not sum due to independent rounding.
[a] See Annex 3.2 for definitions of highway vehicle types.
[b] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-23: N$_2$O Emissions from Mobile Combustion (Tg CO$_2$ Eq.)

Fuel Type/Vehicle Type	1990	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	**40.1**	**51.2**	**50.3**	**49.1**	**46.0**	**43.5**	**40.8**	**38.6**
Passenger Cars	25.4	26.6	25.9	25.1	23.9	22.9	21.8	21.0
Light-Duty Trucks	14.1	23.6	23.5	23.1	21.2	19.7	18.1	16.7
Heavy-Duty Vehicles	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel Highway	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Highway	**3.1**	**3.3**	**3.4**	**3.6**	**3.6**	**3.6**	**3.5**	**3.7**
Ships and Boats	0.4	0.2	0.3	0.4	0.4	0.5	0.4	0.4
Locomotives	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Farm Equipment	1.7	1.8	1.8	1.9	1.8	1.7	1.7	1.8
Construction Equipment	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Aircraft	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Other*	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	**43.5**	**54.8**	**54.1**	**53.1**	**50.0**	**47.5**	**44.8**	**42.8**

+ Less than 0.05 Tg CO$_2$ Eq.
Note: Totals may not sum due to independent rounding.
*"Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-24: CH$_4$ Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990		1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	**201**		**155**	**145**	**137**	**127**	**120**	**112**	**106**
Passenger Cars	125		87	82	77	72	68	63	60
Light-Duty Trucks	65		60	56	54	50	47	44	41
Heavy-Duty Vehicles	10		7	6	5	5	5	4	4
Motorcycles	1		1	1	1	1	1	1	1
Diesel Highway	**1**		**1**	**1**	**1**	**1**	**1**	**1**	**1**
Passenger Cars	+		+	+	+	+	+	+	+
Light-Duty Trucks	+		+	+	+	+	+	+	+
Heavy-Duty Vehicles	1		1	1	1	1	1	1	1
Alternative Fuel Highway	**1**		**3**	**4**	**4**	**5**	**5**	**6**	**6**
Non-Highway	**22**		**22**	**24**	**25**	**25**	**26**	**25**	**27**
Ships and Boats	3		2	3	4	4	4	4	4
Locomotives	3		3	3	3	3	3	3	4
Farm Equipment	7		7	7	7	7	7	6	7
Construction Equipment	4		5	5	5	6	6	6	6
Aircraft	2		3	3	3	3	3	3	3
Other*	2		2	2	2	2	2	2	3
Total	**224**		**181**	**173**	**167**	**159**	**152**	**144**	**140**

+ Less than 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-25: N$_2$O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990		1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	**129**		**165**	**162**	**158**	**148**	**140**	**132**	**125**
Passenger Cars	82		86	83	81	77	74	70	68
Light-Duty Trucks	45		76	76	74	68	63	58	54
Heavy-Duty Vehicles	2		3	3	3	3	3	3	3
Motorcycles	+		+	+	+	+	+	+	+
Diesel Highway	**1**		**1**	**1**	**1**	**1**	**1**	**1**	**1**
Passenger Cars	+		+	+	+	+	+	+	+
Light-Duty Trucks	+		+	+	+	+	+	+	+
Heavy-Duty Vehicles	1		1	1	1	1	1	1	1
Alternative Fuel Highway	**+**		**+**	**+**	**+**	**+**	**+**	**+**	**+**
Non-Highway	**10**		**11**	**11**	**12**	**12**	**12**	**11**	**12**
Ships and Boats	1		1	1	1	1	1	1	1
Locomotives	1		1	1	1	1	1	1	1
Farm Equipment	6		6	6	6	6	6	5	6
Construction Equipment	1		1	1	1	1	1	1	1
Aircraft	1		1	1	1	1	1	1	2
Other*	1		1	1	1	1	1	1	1
Total	**140**		**177**	**174**	**171**	**161**	**153**	**144**	**138**

+ Less than 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-26: NO$_x$, CO, and NMVOC Emissions from Mobile Combustion in 2004 (Gg)

Fuel Type/Vehicle Type	NO$_x$	CO	NMVOC
Gasoline Highway	**3,206**	**55,541**	**3,525**
Passenger Cars	1,749	30,945	1,969
Light-Duty Trucks	1,109	22,107	1,369
Heavy-Duty Vehicles	336	2,361	170
Motorcycles	12	129	18
Diesel Highway	**2,881**	**851**	**171**
Passenger Cars	5	6	3
Light-Duty Trucks	5	5	3
Heavy-Duty Vehicles	2,871	840	165
Alternative Fuel Highwayᵃ	**IE**	**IE**	**IE**
Non-Highway	**3,377**	**22,181**	**2,186**
Ships and Boats	870	1,934	671
Locomotives	812	89	32
Farm Equipment	66	231	18
Construction Equipment	430	615	67
Aircraftᵇ	618	1,032	115
Otherᶜ	582	18,280	1,284
Total	**9,465**	**78,574**	**5,882**

IE (Included Elsewhere)
Note: Totals may not sum due to independent rounding.
ᵃ NO$_x$ emissions from alternative fuel highway vehicles are included under gasoline and diesel highway vehicles.
ᵇ Aircraft estimates include only emissions related to landing and take-off (LTO) cycles, and therefore do not include cruise altitude emissions.
ᶜ "Other" includes gasoline- and diesel-powered recreational, industrial, lawn and garden, light commercial, logging, airport service, and other equipment.

Figure 3-17

Mobile Source CH$_4$ and N$_2$O Emissions

idle, low speed, and cold start conditions. CH$_4$ and NMVOC emissions from motor vehicles are a function of the CH$_4$ content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

Emissions from mobile combustion were estimated by transport mode (e.g., highway, air, rail), fuel type (e.g. motor gasoline, diesel fuel, jet fuel), and vehicle type (e.g. passenger cars, light-duty trucks). Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile combustion emissions. Table 3-22 and Table 3-23 provide CH$_4$ and N$_2$O emission estimates, respectively, in Tg CO$_2$ Eq.; Table 3-24 and Table 3-25 present these estimates in Gg of each gas. Estimates of NO$_x$, CO, and NMVOC emissions in 2004 are given in Table 3-26.[41]

Mobile combustion was responsible for a small portion of national CH$_4$ emissions (0.5 percent) but was the second largest source of N$_2$O (11 percent) in the United States. From 1990 to 2004, CH$_4$ emissions declined by 38 percent, to 2.9 Tg CO$_2$ Eq. (140 Gg), due largely to control technologies employed on highway vehicles in the United States that reduce CO, NO$_x$, NMVOC, and CH$_4$ emissions. The same technologies, however, initially resulted in higher N$_2$O emissions, causing a 26 percent increase in N$_2$O emissions from mobile sources between 1990 and 1998. N$_2$O emissions have subsequently declined 22 percent as improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO$_x$ and N$_2$O per vehicle mile traveled. As a result, N$_2$O emissions in 2004 were 1 percent lower than in 1990, at 42.8 Tg CO$_2$ Eq. (138 Gg) (see Figure 3-17). Overall, CH$_4$ and N$_2$O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Mobile sources comprise the single largest source category of NO$_x$, CO, and NMVOC emissions in the United States. In 2004, mobile combustion contributed 55 percent of NO$_x$ emissions, 90 percent of CO emissions, and 43 percent

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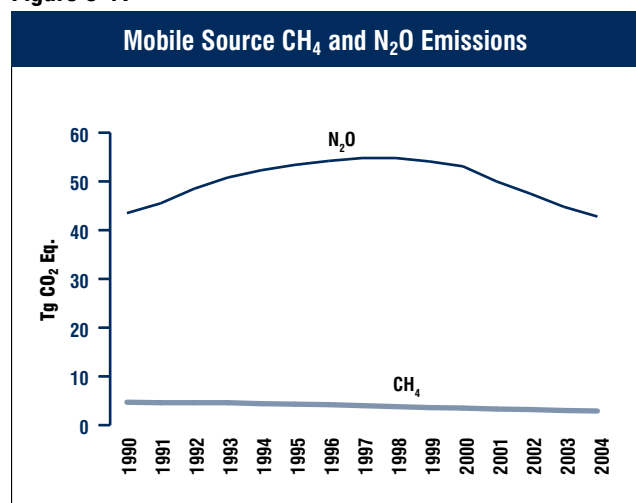
[41] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2004.

of NMVOC emissions. Since 1990, emissions of NO_x from mobile combustion decreased by 22 percent, CO emissions decreased 34 percent, and emissions of NMVOCs decreased by 46 percent.

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Depending upon the category, activity data included such information as fuel consumption, and vehicle miles traveled (VMT). The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

EPA (2005c) and EPA (2003) provided emission estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles,[42] aircraft, and seven categories of non-highway vehicles.[43] These emission estimates reflect preliminary EPA data, which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The methodology used to develop these estimates can be found on EPA's Air Pollutant Emission Trends website, at <http://www.epa.gov/ttn/chief/trends/index.html>.

Highway Vehicles

Emission estimates for gasoline and diesel highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Emission estimates from alternative fuel vehicles (AFVs)[44] were based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel highway vehicles were developed by ICF (2004). These factors were based on EPA and California Air Resources Board (CARB) laboratory test results of different vehicle and control technology types. The EPA and CARB tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emission characteristics of segment 2 was used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2 to approximate average driving characteristics.

Emission factors for AFVs were developed after consulting a number of sources, including Argonne National Laboratory's GREET 1.5–Transportation Fuel Cycle Model (Wang 1999), Lipman and Delucchi (2002), the Auto/Oil Air Quality Improvement Research Program (CRC 1997), the California Air Resources Board (Brasil and McMahon 1999), and the University of California Riverside (Norbeck et al., 1998). The approach taken was to calculate CH_4 emissions from actual test data and determine N_2O emissions from NO_x emissions from the same tests. While the formation of N_2O is highly dependent on the type of catalyst used and the catalyst temperature, tailpipe N_2O is likely to increase as engine out NO_x emissions increase. Thus, as a first approximation, the NO_x to N_2O emission ratio will likely be constant for a given emission control group. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2004 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in *Highway Statistics* (FHWA 1996 through 2005).

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[42] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[43] These categories included: locomotives, marine vessels, farm equipment, construction equipment, other off-highway liquid fuel (e.g. recreational vehicles and lawn and garden equipment), and other off-highway gaseous fuel (e.g., other off-highway equipment running on compressed natural gas).

[44] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other biofuel or dual fuel vehicles that may be partially powered by gasoline or diesel.

VMT was then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using information on shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2004) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2005). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2005d) and EPA (2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for highway vehicles were obtained from the EPA's Office of Transportation and Air Quality (EPA 2005a, 2005b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993), EPA (1994a), EPA (1994b), EPA (1998), EPA (1999), and IPCC/UNEP/OECD/IEA (1997).

Preliminary estimates for NO_x, CO, and NMVOCs were obtained from EPA (2005c) and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site.

Non-Highway Vehicles

Fuel consumption data were employed as a measure of activity for non-highway vehicles, and fuel-specific emission factors were applied.[45] Activity data were obtained from AAR (2005), BEA (1991 through 2005), Benson (2002 through 2004), DOE (1993 through 2004), DESC (2005), DOC (1991 through 2005), DOT (1991 through 2005), EIA (2002a), EIA (2002b), EIA (2005a), EIA (2005b), EIA (2003 through 2004), EIA (1991 through 2005), EPA (2004), and FAA (2005). Emission factors for non-highway modes were taken from IPCC/UNEP/OECD/IEA (1997).

Uncertainty

This section discusses the uncertainty of the emission estimates for CH_4 and N_2O. Uncertainty was analyzed separately for highway vehicles and non-highway vehicles due to differences in their characteristics and their contributions to total mobile source emissions.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since these gases are regulated emissions from motor vehicles in the United States, and the uncertainty of these emission estimates is believed to be relatively low. A much higher level of uncertainty is associated with CH_4 and N_2O emission factors, since emissions of these gases are not regulated in the United States, and unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are also highly complex.

Highway Vehicles

A quantitative uncertainty analysis was conducted for the highway portion of the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, using @ RISK software. The uncertainty analysis was performed on 2004 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following two major sets of input variables: (1) vehicle mile traveled (VMT) data, by vehicle and fuel type and (2) emission factor data, by vehicle, fuel, and control technology type.

Mobile combustion emissions of CH_4 and N_2O per vehicle mile traveled vary significantly due to fuel type and composition, technology type, operating speeds and conditions, type of emission control equipment, equipment age, and operating and maintenance practices. The primary activity data, VMT, are collected and analyzed each year by government agencies.

To determine the uncertainty associated with the activity data used in the calculations of CH_4 and N_2O emissions, the agencies and the experts that supply the data were contacted. Because few of these sources were able to provide quantitative estimates of uncertainty, expert quantitative judgments were used to assess the uncertainty associated with the activity data.

The emission factors for highway vehicles used in the Inventory were obtained from ICF (2004). These factors were based on laboratory testing of vehicles. While the

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[45] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

controlled testing environment simulates real driving conditions, emission results from such testing can only approximate real world conditions and emissions. For some vehicle and control technology types, the testing did not yield statistically significant results within the 95 percent confidence interval, requiring expert judgments to be used in developing the emission factors. In those cases, the emission factors were developed based on comparisons of fuel consumption between similar vehicle and control technology categories.

The estimates of VMT for highway vehicles by vehicle type in the United States were provided by FHWA (1996 through 2005), and were generated though the cooperation of FHWA and state and local governments. These estimates are subject to several possible sources of error, such as unregistered vehicles, and measurement and estimation errors. These VMT were apportioned by fuel type, based on data from DOE (2004), and then allocated to individual model years using temporal profiles of both the vehicle fleet by age and vehicle usage by model year in the United States provided by EPA (2005d) and EPA (2000). While the uncertainty associated with total U.S. VMT is believed to be low, the uncertainty within individual source categories was assumed to be higher given uncertainties associated with apportioning total VMT into individual vehicle categories, by fuel type, by technology type, and equipment age. The uncertainty of individual estimates was assumed to relate to the magnitude of estimated VMT (i.e., it was assumed smaller sources had greater percentage uncertainty). A further source of uncertainty occurs since FHWA and EPA use different definitions of vehicle type and estimates of VMT by vehicle type (provided by FHWA) are broken down by fuel type using EPA vehicle categories.

A total of 69 highway data input variables were simulated through Monte Carlo Simulation technique using @RISK software. Variables included VMT and emission factors for individual vehicle categories and technologies. In developing the uncertainty estimation model, a normal distribution was assumed for all activity-related input variables (e.g., VMT) except in the case of buses, in which a triangular distribution was used. The dependencies and other correlations among the activity data were incorporated into the model to ensure consistency in the model specification and simulation.

Emission factors were assigned uniform distributions, with upper and lower bounds assigned to input variables based on 97.5 percent confidence intervals of laboratory test data. In cases where data did not yield statistically significant results within the 95 percent confidence interval, estimates of upper and lower bounds were made using expert judgment. The bounds for the emission factor-related input variables were typically asymmetrical around their inventory estimates. Bias (or systematic uncertainties) associated with the emission factors was incorporated into the analysis when expert judgments were applied to the laboratory test results in determining the uncertainty characteristics and/or the bounds of the emission factors.[46] The results of this analysis are reported in the section below, titled *Quantitative Estimates of Uncertainty*.

Non-Highway Vehicles

Emissions from non-highway vehicles are a small portion of total emissions from mobiles sources, representing 22 percent of CH_4 emissions from mobile sources and 10 percent of N_2O emissions from mobile sources in 2004. Since they comprise a small share of mobile source emissions, even large uncertainties in these estimates would have a relatively small impact on the total emission estimate for mobile sources. As a result, a quantitative analysis of uncertainty of emissions from non-highway vehicles has not been performed. However, sources of uncertainty for non-highway vehicles are being investigated by examining the underlying uncertainty of emission factors and fuel consumption data.

Overall, a significant amount of uncertainty is associated with the emission estimates for non-road sources. A primary cause is a large degree of uncertainty surrounding emission factors. The IPCC *Good Practice Guidance* reports that CH_4 emissions from aviation and marine sources may be uncertain by a factor of two, while N_2O emissions may be uncertain by an order of magnitude for marine sources and several orders of magnitude for aviation. No information is provided on the uncertainty of emission factors for other non-highway sources.

Fuel consumption data have a lower uncertainty than emission factors, though large uncertainties do exist for individual sources. Fuel consumption for off-highway

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[46] Random uncertainties are the main focus of statistical uncertainty analysis. Uncertainty estimates elicited from experts include both random and systematic uncertainty. Hence, both these types of uncertainty are represented in this uncertainty analysis.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CH$_4$ and N$_2$O Emissions from Mobile Sources (Tg CO$_2$ Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO$_2$ Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO$_2$ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH$_4$	2.9	2.7	3.0	-8%	+4%
Mobile Sources	N$_2$O	42.8	36.1	55.3	-16%	+29%

[a]Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

vehicles (i.e., equipment used for agriculture, construction, lawn and garden, railroad, airport ground support, etc., as well as recreational vehicles) was generated by EPA's NONROAD model (EPA 2004). This model estimates fuel consumption based on estimated equipment/vehicle use (in hours) and average fuel consumed per hour of use. Since the fuel estimates are not based upon documented fuel sales or consumption, a fair degree of uncertainty accompanies these estimates.

Estimates of distillate fuel sales for ships and boats were obtained from EIA's *Fuel Oil and Kerosene Sales* (EIA 1991 through 2004). These estimates have a moderate level of uncertainty since EIA's estimates are based on survey data and reflect sales to economic sectors, which may include use by both mobile and non-mobile sources within a sector. Domestic consumption of residual fuel by ships and boats is obtained from EIA (2005a). These estimates fluctuate widely from year to year, and are believed to be highly uncertain. In addition, estimates of distillate and residual fuel sales for ships and boats are adjusted for bunker fuel consumption, which introduces an additional (and much higher) level of uncertainty.

Jet fuel and aviation gasoline consumption data are obtained from EIA (2005a). Estimates of jet fuel consumption are also adjusted downward to account for international bunker fuels, introducing a significant amount of uncertainty. Additionally, all jet fuel consumption in the transportation sector is assumed to be consumed by aircraft. Some fuel purchased by airlines is not used in aircraft but instead used to power auxiliary power units, in ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

In calculating CH$_4$ emissions from aircraft, an average emission factor is applied to total jet fuel consumption. This average emission factor takes into account the fact that CH$_4$ emissions occur only during the landing and take-off (LTO) cycles, with no CH$_4$ being emitted during the cruise cycle. However, a better approach would be to apply emission factors based on the number of LTO cycles.

Quantitative Estimates of Uncertainty

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-27. Mobile combustion CH$_4$ emissions in 2004 were estimated to be between 2.7 and 3.0 Tg CO$_2$ Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 8 percent below to 4 percent above the 2004 emission estimate of 2.9 Tg CO$_2$ Eq. Also at a 95 percent confidence level, mobile combustion N$_2$O emissions in 2004 were estimated to be between 36.1 and 55.3 Tg CO$_2$ Eq., indicating a range of 16 percent below to 29 percent above the 2004 emission estimate of 42.8 Tg CO$_2$ Eq.

This uncertainty analysis is a continuation of a multi-year process for developing credible quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. In the upcoming years, the type and the characteristics of the actual probability density functions underlying the input variables will be identified and more credibly characterized. Accordingly, the quantitative uncertainty estimates reported in this section should be considered as preliminary and illustrative.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative

assessment of the emission estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between this year's and last year's Inventories was also conducted, and was qualitatively assessed to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure the highest quality estimates, the methodology is continuously revised based on comments from internal and external reviewers. This year, a number of adjustments were made to the historical data. Vehicle age distributions for 1999 forward were revised based on new data obtained from EPA's MOVES model (EPA 2005d). Diesel fractions for light trucks and medium-heavy trucks for 1998 through 2003 were updated based on data obtained from the *Vehicle Inventory and Use Survey* (Census 2000). The value for diesel consumption by boats was adjusted to remove all military bunker fuel consumption, which had not been properly removed from the estimates in previous version of the Inventory. Lastly, vehicle miles traveled and fuel consumption estimates for non-highway vehicles were revised for 2003 based on updated data from FHWA's *Highway Statistics* (FHWA 2005).

As a result of these changes, average estimates of CH_4 and N_2O emissions from mobile combustion decreased less than 0.1 Tg CO_2 Eq. (less than 1 percent) each year for the period 1990 through 2003.

Planned Improvements

While the data used for this report represent the most accurate information available, three areas have been identified that could potentially be improved in the short term given available resources:

1) *Update CH_4 and N_2O Emission Factors for Highway Vehicles*—A number of recent efforts have focused on improving the estimates of CH_4 and N_2O Emission Factors for alternative fuel highway vehicles. These studies are expected to be available next year, and will be reviewed to determine whether the current emission factors can be updated.

2) Continue the *Reconciliation of Fuel Consumption Estimates used for Calculating N_2O/CH_4 and CO_2*—

Estimates of transportation fuel consumption by fuel type from EIA are used as the basis for estimating CO_2 emissions from the transportation sector. These estimates are then apportioned to mode and vehicle category based on "bottom up" estimates of fuel consumption from sources such as FHWA's *Highway Statistics* (FHWA 1996 through 2004) and DOE's *Transportation Energy Data Book* (DOE 1993 through 2004). These sources are also used to develop N_2O and CH_4 estimates. The EPA fuel consumption estimates, however, differ from the estimates derived using "bottom up" sources. For this Inventory, estimates of distillate fuel consumption have been reconciled. Potential improvements include reconciling additional fuel consumption estimates from EIA and other data sources, and revising the current process of allocating CO_2 emissions to particular vehicle types.

3) *Improve consideration of emissions from trucks used off-road*—Some light- and heavy-duty trucks travel for a portion of their mileage off-road. N_2O and CH_4 estimates for highway vehicles are developed based on vehicle mileage data from FHWA's *Highway Statistics*, which in turn, are drawn from the Highway Performance Monitoring System (HPMS). These emission estimates do not address travel by trucks off-road. Gasoline fuel consumed by trucks used off-road for construction, agriculture, and other industrial/ commercial uses is reported in *Highway Statistics*, and is included as part of the non-road agriculture and construction categories. However, diesel fuel consumed by trucks used off-road is not addressed in the Inventory, and further work should be conducted to develop estimates of off-road truck use of diesel fuel. In addition, default emission factors from IPCC are applied to the off-highway modes. As a result, the emissions factors for agricultural equipment are applied both to equipment and trucks used in agriculture, and emissions factors for construction equipment are applied both to equipment and trucks used in construction.

4) *Improve estimation of VMT by vehicle/fuel type category*—The current Inventory process for estimating VMT by vehicle/fuel type category involves apportioning VMT by vehicle type to each fuel type on the basis of fuel consumption. While this is a reasonable simplification, this approach implicitly assumes the same average fuel economy for gasoline and diesel vehicles. A more accurate apportionment for VMT by fuel type for light-duty trucks and medium/heavy-duty trucks could potentially be developed

using data on vehicle travel from the Vehicle Inventory and Use Survey (Census 2000) and other publications, or using VMT breakdowns by vehicle/fuel type combinations from the MOBILE6 or MOVES models.

3.5. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. All 115 gassy underground coal mines employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, twenty-one U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2004, eleven coal mines collected CH_4 from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. In addition, one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. Two of the coal mines that sold gas to pipelines also used CH_4 to generate electricity or fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2004 were estimated to be 56.3 Tg CO_2 Eq. (2,682 Gg), a decline of 31 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 69 percent, surface mines accounted for 17 percent, and post-mining emissions accounted for 14 percent. In 1993, CH_4 generated from underground mining dropped, primarily due to labor strikes at many large underground mines. In 1994 and 1995, CH_4 emissions increased due to resumed production at high emitting mines after the labor strike. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. CH_4 emissions increased slightly in 2003 due to additional gas

Table 3-28: CH$_4$ Emissions from Coal Mining (Tg CO$_2$ Eq.)

Activity	1990		1997	1998	1999	2000	2001	2002	2003	2004
Underground Mining	62.1		44.3	44.5	41.7	39.4	38.0	35.9	38.6	38.9
Liberated	67.6		55.7	58.6	54.4	54.0	54.2	53.3	53.6	52.8
Recovered & Used	(5.6)		(11.4)	(14.1)	(12.7)	(14.6)	(16.1)	(17.4)	(15.0)	(13.9)
Surface Mining	10.4		9.3	9.4	9.0	8.8	9.2	8.8	8.4	9.3
Post-Mining (Underground)	7.7		7.4	7.4	6.8	6.7	6.8	6.4	6.4	6.6
Post-Mining (Surface)	1.7		1.5	1.5	1.5	1.4	1.5	1.4	1.4	1.5
Total	**81.9**		**62.6**	**62.8**	**58.9**	**56.3**	**55.5**	**52.5**	**54.8**	**56.3**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-29: CH$_4$ Emissions from Coal Mining (Gg)

Activity	1990		1997	1998	1999	2000	2001	2002	2003	2004
Underground Mining	2,956		2,111	2,118	1,985	1,878	1,811	1,708	1,839	1,851
Liberated	3,220		2,654	2,791	2,589	2,573	2,580	2,538	2,554	2,512
Recovered & Used	(265)		(543)	(673)	(605)	(695)	(769)	(830)	(716)	(661)
Surface Mining	497		445	448	428	417	438	420	402	444
Post-Mining (Underground)	367		354	352	325	317	323	304	305	315
Post-Mining (Surface)	81		72	73	69	68	71	68	65	72
Total	**3,900**		**2,983**	**2,990**	**2,807**	**2,679**	**2,644**	**2,500**	**2,611**	**2,682**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

drainage being vented to the atmosphere and a reduction in CH_4 recovery. Recovery continued to decrease in 2004 with reduced production from pre-drainage wells, increased use of horizontal gob wells that are vented to the atmosphere, and temporary closure of a major project due to a mine fire. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 2004.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[47] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1991	368,635	532,656	901,291
1992	368,627	534,290	902,917
1993	318,478	539,214	857,692
1994	362,065	575,529	937,594
1995	359,477	577,638	937,115
1996	371,816	593,315	965,131
1997	381,620	607,163	988,783
1998	378,964	634,864	1,013,828
1999	355,433	642,877	998,310
2000	338,173	635,592	973,765
2001	345,305	676,142	1,021,446
2002	324,219	667,619	991,838
2003	320,047	651,251	971,297
2004	333,424	687,497	1,020,921

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty-one mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. This calculation was complicated by the fact that most CH_4 is not recovered and used during the same year in which the particular coal seam is mined. In 2004, eleven active coal mines sold recovered CH_4 into the local gas pipeline networks, while one coal mine used recovered CH_4 on site. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's *Coal Industry Annual* (see Table 3-30) (EIA 2004), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average *in situ* CH_4 content of the coal. Revised data on *in situ* CH_4 content and emissions factors are taken from EPA (1996) and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to

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[47] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH$_4$ Emissions from Coal Mining (Tg CO$_2$ Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO$_2$ Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO$_2$ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH$_4$	56.3	54.1	58.6	-4%	+4%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

be 32.5 percent of the average *in situ* CH$_4$ content of coals mined in the basin.

Uncertainty

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH$_4$ emissions (Mutmansky and Wang 2000). Estimates of CH$_4$ liberated and recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may increase if the drainage area is found to be larger than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH$_4$ emissions in 2004 were estimated to be between 54.1 and 58.6 Tg CO$_2$ Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 4 percent below to 4 percent above the 2004 emission estimate of 56.3 Tg CO$_2$ Eq.

Recalculations Discussion

Recalculations were performed on all years with negligible changes in 1994, 1996, and 1998-2002, as QA/QC of databases uncovered that emissions avoided had been miscalculated. Some recalculations were done in 2003 on Alabama mines but were not linked retroactively. These recalculations either led to no change in net emissions, or a change of 0.1 Tg CO$_2$ Eq. Emissions avoided for 2003 were adjusted downwardly as a major operator reported in 2004 that double-counting of some pre-drainage wells had previously occurred. Correction of this error led to a reduction in emissions avoided of 1.0 Tg CO$_2$ Eq. which changed total emissions for 2003 from 53.8 to 54.8 Tg CO$_2$ Eq.

Planned Improvements

To reduce the uncertainty associated with the radius of influence of each well, the appropriate drainage radius will be investigated for future inventories. Since the number of wells counted may increase if the drainage area is found to be larger than currently estimated, additional mines may be included in future estimates of recovery.

3.6. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

All underground and surface coal mining liberates CH$_4$ as part of the normal mining operations. The amount of CH$_4$ liberated depends on the amount that resides in the coal ("*in situ*") and surrounding strata when mining occurs. The in-situ CH$_4$ content depends upon the amount of CH$_4$ created during the coal formation (i.e., coalification) process, and the geologic characteristics of the coal seams. During coalification, more deeply buried deposits tend to generate

Table 3-32: CH$_4$ Emissions from Abandoned Coal Mines (Tg CO$_2$ Eq.)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Abandoned Underground Mines	6.0		8.6	8.6	8.7	8.0	7.6	7.3	7.1
Recovered & Used	0.0		1.7	1.6	1.5	1.5	1.6	1.5	1.5
Total	**6.0**		**6.9**	**6.9**	**7.2**	**6.6**	**6.0**	**5.8**	**5.6**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH$_4$ Emissions from Abandoned Coal Mines (Gg)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Abandoned Underground Mines	287		407	407	415	383	362	349	339
Recovered & Used	0		79	77	72	70	74	72	70
Total	**287**		**328**	**330**	**343**	**313**	**288**	**277**	**269**

Note: Totals may not sum due to independent rounding.

more CH$_4$ and retain more of the gas after uplift to minable depths. Deep underground coal seams generally have higher CH$_4$ contents than shallow coal seams or surface deposits.

Underground coal mines contribute the largest share of CH$_4$ emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH$_4$ after closure. As mines mature and coal seams are mined through, mines close and are abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH$_4$ that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH$_4$ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH$_4$ at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH$_4$ migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;

- CH$_4$ flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH$_4$ emissions ranged from 6.0 to 9.0 Tg CO$_2$ Eq. from 1990 through 2004, varying, in general, by approximately 1 to 18 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Abandoned mine emissions peaked in 1996 (9.0 Tg CO$_2$ Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than thirteen gassy mine closures during each of the years from 1998 through 2004, with only one closure in 2004. By 2004, abandoned mine emissions were reduced to 5.7 Tg CO$_2$ Eq. (see Table 3-32 and Table 3-33).

Methodology

Estimating CH$_4$ emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH$_4$ from the coal to the mine void is primarily dependent on mine's emissions when active and the extent to which the mine is flooded or sealed. The CH$_4$ emission rate before abandonment reflects the gas content of the coal, rate

of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, P_r, declines as described by the isotherm. The emission rate declines because the mine pressure (P_w) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i(1+bD_it)^{(-1/b)}$$

Where:

- q is the gas rate at time t in mcf/d

- q_i is the initial gas rate at time zero (t_0) in million cubic feet per day (mcfd)

- b is the hyperbolic exponent, dimensionless

- D_i is the initial decline rate, 1/yr

- t is elapsed time from t_0 in years

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves are also affected by both sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within 8 years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_ie^{(-Dt)}$$

Where:

- q is the gas flow rate at time t in mcf/d

- · q_i is the initial gas flow rate at time zero (t_0) in mcfd

- D is the decline rate, 1/yr

- t is elapsed time from t_0 in years

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 -$ initial emissions from sealed mine / emission rate at abandonment prior to sealing). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 438 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 263 of the 438 mines (or 60 percent) is known to be either 1) vented to the atmosphere, 2) sealed to some degree (either earthen or concrete seals), or 3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 40 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production

by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, throughout the 20th century. The data was used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emissions rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to ventilation data for the total CH_4 liberation rate for fourteen mines that closed between 1992 and 2004. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions. From 1993 through 2004, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The emission estimates from underground ventilation systems were based on actual measurement data, which are believed to have relatively low uncertainty. A degree of imprecision was introduced because the measurements were not continuous, but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used may have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 liberated and recovered by degasification systems are also relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-34. Abandoned coal mines CH_4 emissions in 2004 were estimated to be between 4.7 and 7.0 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 18 percent below to 23 percent above the 2004 emission estimate of 5.6 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the

Table 3-34: Tier 2 Quantitative Uncertainty Estimates for CH$_4$ Emissions from Abandoned Underground Coal Mines (Tg CO$_2$ Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO$_2$ Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO$_2$ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH$_4$	5.6	4.7	7.0	-18%	+23%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

unknown status mines (which account for 40 percent of the mines), with a ±50 percent uncertainty.

QA/QC and Verification

As part of a Tier 2 analysis, the United States undertook an effort to verify the model results used in the U.S. Inventory with field measurements. Field measurements were used to test the accuracy of the mathematical decline curves to be used for basin-specific emissions estimates. A series of field measurements were conducted at abandoned mine vent locations across the United States. Between November 1998 and February 2000, EPA recorded measurements at five mines that were not flooded. Measurements were recorded at two abandoned mines located in Ohio and Virginia continuously for 6 to 12 hours. As the methodology was finalized, EPA measured emissions from three additional mines located in Illinois and Colorado. These measurements were recorded hourly for 3 to 4 days and were normalized to average barometric pressures. Prior to these measurements, EPA's Office of Research and Development initiated a field research program in the early 1990s. Data for 21 abandoned mines located throughout the Northern and Central Appalachian, Black Warrior, and Illinois Basins were collected using similar techniques.

Measurements for all field data recorded were plotted against predicted emissions as part of the two studies from 1991 through 2000. Emission rates from nine of the ten mines that were measured fall very close to the predicted mid-case decline rate for their respective basins. For the exponential decline curve fit to the flooding mines, six of nine measurements fall within a 95 percent predictive confidence interval of the mean.

Of the abandoned mines in the database, only about 12 percent of the mines maintain vents to the atmosphere. Therefore, it is difficult to obtain field data. Additional field measurements, however, would be beneficial to further calibrate the equations defined above. Furthermore, it would be useful to extend measurements of diffuse emissions from sealed mines, since they comprise 44 percent of total mines.

Recalculations Discussion

In 2005, CH$_4$ emissions from abandoned mines were recalculated for 1990-2003. QA/QC of the database uncovered several mines that had been accounted for more than once. Changes in MSHA's database regarding date of abandonment for several mines led to adding them more than once—once for each time reported abandoned. Also, sale of mines and resultant renaming caused two mines to be added twice with different names.

Emissions for 2003 were recalculated, as additional recovery data for one mine was obtained, resulting in an increase of 0.1 Tg CO$_2$ Eq. in the amount of CH$_4$ recovered and used. Recalculation of the CH$_4$ emissions from flooded, abandoned mines yielded a decrease of 0.1 Tg CO$_2$ Eq. in CH$_4$ emitted for 2003. Additionally, a research project conducted on abandoned mine status yielded updates to the status of 19 mines, ten of which were previously designated "unknown." Recalculations led to a decrease in emissions each inventory year. The total emissions for 2003 decreased from 6.2 Tg CO$_2$ Eq. to 5.8 Tg CO$_2$ Eq. Data for other years from 1990-2002 saw similar changes, the most significant decrease occurring in total emissions for 2000 of 0.5 Tg CO$_2$ Eq.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH$_4$ emissions from petroleum systems are primarily associated with crude oil production, transportation, and

refining operations. During each of these activities, CH_4 is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Total CH_4 emissions from petroleum systems in 2004 were 25.65 Tg CO_2 Eq. (1,222 Gg). Since 1990, emissions declined due to a decline in domestic oil production and industry efforts to make emissions reductions (see Table 3-38 and Table 3-39). The various sources of emissions are detailed below.

Production Field Operations. Production field operations account for over 97 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 90 percent of the emissions from the production sector, fugitive emissions account for four percent, combustion emissions six percent, and process upset emissions just barely over one-tenth of a percent. The most dominant sources of vented emissions are offshore oil platforms (shallow and deep water platforms), field storage tanks and natural-gas-powered pneumatic devices (low bleed and high bleed). These five sources alone emit over

84 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and combustion emissions from all equipment housed on the platform. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle up and down to modulate the system. Two additional large sources, chemical injection pumps and gas engines, together account for 10 percent of emissions from the production sector. The remaining eight percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions.

Crude Oil Transportation. Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 66 percent of CH_4 emissions from crude oil transportation. Fugitive

Table 3-35: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Production Field Operations	33.8		29.0	27.8	27.1	26.7	26.1	25.3	25.0
Pneumatic device venting	11.5		10.6	10.2	10.0	10.0	9.9	9.8	9.8
Tank Venting	3.8		3.4	3.2	3.2	3.2	3.2	3.1	3.0
Combustion & process upsets	1.8		1.7	1.6	1.6	1.6	1.6	1.5	1.5
Misc. venting & fugitives	16.2		12.8	12.3	11.8	11.4	10.9	10.3	10.2
Wellhead fugitives	0.5		0.5	0.5	0.5	0.5	0.5	0.5	0.5
Crude Oil Transportation	0.1		0.1	0.1	0.1	0.1	0.1	0.1	0.1
Refining	0.5		0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	34.4		29.7	28.5	27.8	27.4	26.8	25.9	25.7

Table 3-36: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Production Field Operations	1,609		1,381	1,326	1,292	1,271	1,242	1,203	1,188
Pneumatic device venting	545		504	488	478	475	473	466	464
Tank Venting	179		162	154	154	154	151	150	143
Combustion & process upsets	88		80	76	76	75	75	73	73
Misc. venting & fugitives	771		610	584	562	545	520	492	486
Wellhead fugitives	26		25	24	22	22	23	22	23
Crude Oil Transportation	7		6	6	5	5	5	5	5
Refining	25		27	27	28	27	27	27	28
Total	1,640		1,414	1,358	1,325	1,303	1,274	1,236	1,222

emissions, almost entirely from floating roof tanks, account for 18 percent. The remaining 16 percent is distributed among four additional sources within these two categories.

Crude Oil Refining. Crude oil refining processes and systems account for only slightly over two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 87 percent of the emissions, while fugitive and combustion emissions account for approximately six and seven percent respectively. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and from unburned CH_4 in engine exhausts and flares.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1999, Radian 1996e). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are very small compared to CH_4 emissions upstream of oil refineries.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999) and activity factors that are based on EPA (1999) and Radian (1996e) studies. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). The report provides emission factors and activity factors for all activities except those related to offshore oil production. For offshore oil production, two

emission factors were calculated using data collected over a one-year period for all federal offshore platforms (MMS 2005c). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2004. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Minerals Management Service statistics (MMS 2005a,b,d).

Activity factors for years 1990 through 2004 were collected from a wide variety of statistical resources. For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for Radian (1996e). For example, Radian (1996e) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for Radian (1996e). In other cases, the activity factor was held constant from 1990 through 2004 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. See Annex 3.5 for additional detail.

Nearly all emission factors were taken from Radian (1996e) and EPA (1995, 1999). The remaining emission factors were taken from the following sources: EPA default values, MMS reports (MMS 2005c), the Exploration and Production (E&P) Tank model (DB Robinson Research Ltd. 1997), and the consensus of industry peer review panels.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990-2004, 1995-2004, 1995-2005), the API *Basic Petroleum Data Book* (API 2004), *Methane Emissions from the Natural Gas Industry* by the Gas Research Institute and EPA (Radian 1996a-d,f), consensus of industry peer review panels, MMS reports (MMS 2001, 2005a,b,d), the *Oil & Gas Journal* (OGJ 2004a-b) and the United States Army Corps of Engineers (1995-2003).

Uncertainty

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and

the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison with a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of five major sources, which account for 86 percent of the total emissions, the uncertainty surrounding these five sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-37. Petroleum systems CH_4 emissions in 2004 were estimated to be between 17.2 and 61.8 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 33 percent below to 141 percent above the 2004 emission estimate of 25.7 Tg CO_2 Eq.

Recalculations Discussion

Estimates of CH_4 from petroleum systems contain one major change with respect to previous inventories. In previous years, offshore production emissions were calculated as eight separate sources (2 categories of fugitives, 2 categories of venting, 2 categories of combustion, and 2 categories of process upsets) but new analysis of the 2000 GOADS report (MMS 2005c) yields comprehensive emissions factors for shallow water and deep water gas platforms. The shallow water and deep water sources from the GOADS analysis account for all offshore emissions and have replaced the eight sources from previous inventories.

The combination of these changes resulted in an average annual increase of 11.8 Tg CO_2 Eq. (63 percent) in CH_4 emissions from petroleum systems for the period 1990 through 2003. Emissions from offshore oil platforms account for the entire change in emissions.

Planned Improvements

Several improvements to the emission estimates are being evaluated that fine-tune and better track changes in emissions. These include, but are not limited to, some activity factors that are also accounted for in the Natural Gas STAR Program emission reductions, some emission factors for consistency between emission estimates from Petroleum Systems and Natural Gas Systems, and new data from recent studies that bear on both emission factors and activity factors. The growing body of data in the Natural Gas STAR Program, coupled with an increasing number of oil and gas companies doing internal greenhouse gas emissions inventories, provides an opportunity to reevaluate emission and activity factors, as well as the methodology currently used to project emissions from the base year.

Changes in state regulations, new facility construction, and activities of natural gas industry entities outside of the Natural Gas STAR program can lead to alterations in emissions profile that are not specifically accounted for in the current emissions inventory. Research of publicly available data sources will be conducted to develop a methodology for

Table 3-37: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH_4	25.7	17.2	61.8	-33%	+141%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

adjusting emissions factors over the inventory time series to account for these fluctuations.

3.8. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 118.8 Tg CO_2 Eq. (5,658 Gg) of CH_4 in 2004, a slight decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions.

CH_4 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engines and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 33 percent of CH_4 emissions from natural gas systems in 2004.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of CH_4 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine

Table 3-38: CH$_4$ Emissions from Natural Gas Systems (Tg CO$_2$ Eq.)*

Stage	1990		1998	1999	2000	2001	2002	2003	2004
Field Production	34.0		38.2	35.3	39.2	42.3	43.5	42.1	39.3
Processing	14.8		14.8	14.7	14.9	15.0	14.5	14.5	14.0
Transmission and Storage	46.8		44.3	43.1	43.1	39.6	41.3	41.2	38.4
Distribution	31.0		28.2	28.7	29.6	28.7	26.0	26.9	27.1
Total	126.7		125.4	121.7	126.7	125.6	125.4	124.7	118.8

*Including CH$_4$ emission reductions achieved by the Natural Gas STAR program.
Note: Totals may not sum due to independent rounding.

Table 3-39: CH$_4$ Emissions from Natural Gas Systems (Gg)*

Stage	1990		1998	1999	2000	2001	2002	2003	2004
Field Production	1,621		1,819	1,679	1,865	2,014	2,073	2,007	1,873
Processing	706		704	698	708	716	691	688	667
Transmission and Storage	2,230		2,110	2,051	2,052	1,884	1,968	1,963	1,827
Distribution	1,477		1,341	1,369	1,407	1,367	1,239	1,281	1,291
Total	6,034		5,973	5,797	6,033	5,981	5,971	5,939	5,658

*Including CH$_4$ emission reductions achieved by the Natural Gas STAR program.
Note: Totals may not sum due to independent rounding.

compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 32 percent of emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,135,000 miles of distribution mains in 2004, an increase from just over 944,000 miles in 1990 (OPS 2005b). Distribution system emissions, which account for approximately 23 percent of emissions from natural gas systems, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel).[48] An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage. Distribution system emissions in 2004 were 13 percent lower than 1990 levels.

Methodology

The primary basis for estimates of CH_4 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 100 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors. For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991-1998); American Petroleum Institute (API 2005); Minerals and Management Service (MMS 2005a-e); Monthly Energy Review (EIA 2005e); Natural Gas Liquids Reserves Report (EIA 2004b); Natural Gas Monthly (EIA 2005c,d,f); the Natural Gas STAR Program annual emissions savings (EPA 2005); Oil and Gas Journal (OGJ 1999–2005); Office of Pipeline Safety (OPS 2005a-b) and other Energy Information Administration publications (EIA 2004a, 2005a,b,g). Data from a program for estimating emissions from hydrocarbon production tanks is incorporated (DB Robinson Research Ltd. 1997). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2005) and the Alabama State Oil and Gas Board (Alabama 2005). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2204); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2005); Montana Board of Oil and Gas Conservation (Montana 2005); Oklahoma Geological Survey (Oklahoma 2005); Morgan Stanley (Morgan Stanley 2005)Rocky Mountain Production Report (Lippman (2003); New Mexico Oil Conservation Division (New Mexico 2005a,b); Texas Railroad Commission (Texas 2005a-c); Utah Division of Oil, Gas and Mining (Utah 2005). Emissions factors were taken from EPA/GRI (1996).

Uncertainty

An quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding inventory estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density

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[48] The percentages of total emissions from each stage may not sum to 100 percent due to independent rounding.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH$_4$ Emissions from Natural Gas Systems (Tg CO$_2$ Eq. and Percent)

| Source | Gas | 2004 Emission Estimate (Tg CO$_2$ Eq.) | Uncertainty Range Relative to Emission Estimate[a] | | | |
| | | | (Tg CO$_2$ Eq.) | | (%) | |
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Natural Gas Systems	CH$_4$	118.8	84.3	155.5	-29%	+31%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall.

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH$_4$ emissions in 2004 were estimated to be between 84.3 and 155.5 Tg CO$_2$ Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 29 percent below to 31 percent above the 2004 emission estimate of 118.8 Tg CO$_2$ Eq.

Recalculations Discussion

Significant changes were made to the emission calculations in the Production sector. The first change was a restructuring of sources to follow the EIA's National Energy Modeling System (NEMS) regions for oil and gas production in the United States. The EIA's NEMS groups oil and gas production into six distinct regions: North East, Mid-Central, Rocky Mountains, South West, West Coast, and Gulf Coast. The first step in the restructuring of the emissions from the production sector was to divide emissions from each source into NEMS regions using equivalent emissions factors but localized activity data. The net effect of this restructuring on the historical emission estimates is negligible, but did involve changes in the uncertainty estimate calculations. Several large sources from the previous year's inventory were broken down into smaller regional sources and a new set of top-ten sources that represent a major portion of the total emissions from the natural gas industry have been chosen to calculate the uncertainty of the estimate. A future step in the restructuring of the production sector emissions estimates will be to develop specific region emissions and activity factors.

Another change in this year's estimates is the methodology for calculating offshore natural gas production emissions. In previous years, offshore production emissions were calculated as five separate sources (2 categories of fugitives, venting, flaring, and emergency shut-downs), but analysis of new data in the 2000 Gulf-wide Offshore Air Data System (GOADS) report (MMS 2005c) yields comprehensive emissions factors for shallow water and deep water gas platforms. The shallow water and deep water sources from the GOADS analysis account for all offshore emissions and have replaced the five sources from previous inventories.

Finally, the emission factor for plastic pipelines (used in the distribution sector) was changed this year from the previous 11.40 scf/hr to 5.85scf/hr based on additional data points from the Southern California Gas Company (1991). The new emission factor reflects plastic pipeline produced before 1982; a lower emission factor of 0.99 scf/hr is estimated for plastic pipeline produced after 1982. Because activity data can not be appropriately disaggregated into these two time frames, the pre-1982 value is used for all years. If activity data become available to distinguish pre- and post-1982 plastic pipeline the emission estimates will be subsequently revised.

The combination of these methodological and historical data changes resulted in an average annual decrease of 4.5 Tg CO$_2$ Eq. (3 percent) in CH$_4$ emissions from natural gas systems for the period 1990 through 2003.

Planned Improvements

Several improvements to the emission estimates are being evaluated that fine-tune and better track changes in emissions. These include, but are not limited to, some activity factors that are also accounted for in the Natural Gas STAR Program emission reductions, some emission factors for consistency between emission estimates from the Petroleum Systems and Natural Gas Systems source categories, and new data from recent studies that bear on both emission factors and activity factors. The growing body of data in the Natural Gas STAR Program, coupled with an increasing number of oil and gas companies doing internal greenhouse gas emissions inventories, provides an opportunity to reevaluate emission and activity factors, as well as the methodology currently used to project emissions from the base year.

Changes in state regulations, new facility construction, and activities of natural gas industry entities outside of the Natural Gas STAR program can lead to fluctuations in emissions that are not specifically accounted for in the current emissions inventory. Research of publicly available data sources will be conducted to develop a methodology for adjusting emissions factors over the inventory time series to account for these fluctuations.

Improvements to emissions and activity factors in the NEMS production regions will be a major focus in upcoming inventories. This second step in the restructuring of the production sector estimates requires the development of unique regional factors to reflect the differences in the natural gas industries' operations throughout the United States.

3.9. Municipal Solid Waste Combustion (IPCC Source Category 1A5)

Combustion is used to manage about 7 to 17 percent of the municipal solid wastes (MSW) generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000c, Goldstein and Matdes 2001, Kaufman et al. 2004). Almost all combustion of municipal solid wastes in the United States occurs at waste-to-energy facilities where energy is recovered, and thus emissions from waste combustion are accounted for in the Energy chapter. Combustion of municipal solid wastes results in conversion of the organic inputs to CO_2. According to the IPCC Guidelines, when the CO_2 emitted is of fossil origin,

Table 3-41: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Tg CO_2 Eq.)

Gas/Waste Product	1990		1998	1999	2000	2001	2002	2003	2004
CO_2	10.9		17.1	17.6	17.9	18.6	18.9	19.4	19.4
Plastics	8.0		11.4	12.0	12.1	12.6	12.6	12.9	12.9
Synthetic Rubber in Tires	0.2		0.9	0.9	0.9	0.9	1.0	1.0	1.0
Carbon Black in Tires	0.2		1.2	1.2	1.2	1.2	1.2	1.3	1.3
Synthetic Rubber in MSW	1.3		1.6	1.6	1.7	1.8	1.8	1.8	1.8
Synthetic Fibers	1.2		2.0	2.0	2.1	2.2	2.2	2.3	2.3
N_2O	0.5		0.4	0.4	0.4	0.5	0.5	0.5	0.5
Total	**11.4**		**17.5**	**18.0**	**18.3**	**19.1**	**19.4**	**19.9**	**19.9**

Table 3-42: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Gg)

Gas/Waste Product	1990		1998	1999	2000	2001	2002	2003	2004
CO_2	10,919		17,094	17,632	17,921	18,634	18,862	19,360	19,360
Plastics	7,953		11,427	11,950	12,095	12,599	12,630	12,885	12,885
Synthetic Rubber in Tires	191		887	890	893	895	952	1,010	1,010
Carbon Black in Tires	249		1,160	1,164	1,167	1,170	1,245	1,320	1,320
Synthetic Rubber in MSW	1,330		1,627	1,612	1,682	1,793	1,804	1,848	1,848
Synthetic Fibers	1,196		1,992	2,016	2,085	2,177	2,231	2,298	2,298
N_2O	2		1	1	1	1	2	2	2

Table 3-43: NO$_x$, CO, and NMVOC Emissions from Municipal Solid Waste Combustion (Gg)

Gas/Source	1990	1998	1999	2000	2001	2002	2003	2004
NO$_x$	**82**	**145**	**143**	**114**	**114**	**134**	**134**	**134**
Waste Incineration	44	49	48	38	38	45	45	45
Open Burning	38	96	95	76	76	89	89	89
CO	**978**	**2,826**	**2,725**	**1,670**	**1,672**	**1,672**	**1,672**	**1,672**
Waste Incineration	337	69	66	40	41	41	41	41
Open Burning	641	2,757	2,659	1,630	1,631	1,631	1,631	1,631
NMVOCs	**222**	**326**	**302**	**257**	**258**	**281**	**282**	**282**
Waste Incineration	44	23	19	15	16	18	18	18
Open Burning	178	303	284	242	242	264	264	264

Note: Totals may not sum due to independent rounding.

it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is carbon derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net carbon flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. Tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the municipal solid waste combustion estimate, though waste disposal practices for tires differ from the rest of municipal solid waste.

Approximately 30 million metric tons of municipal solid wastes were combusted in the United States in 2003 (see Table 3-46). CO_2 emissions from combustion of municipal solid wastes rose 78 percent since 1990, to an estimated 19.4 Tg CO_2 Eq. (19,360 Gg) in 2004, as the volume of plastics and other fossil carbon-containing materials in MSW increased (see Table 3-41 and Table 3-42). Waste combustion is also a source of N$_2$O emissions (De Soete 1993). N$_2$O emissions from municipal solid waste combustion were estimated to be 0.5 Tg CO_2 Eq. (1 Gg) in 2004, and have not changed significantly since 1990.

Indirect greenhouse gases are also emitted during waste incineration and open burning, as shown in Table 3-43. These emissions are a relatively small portion of the overall indirect greenhouse gas emissions, comprising less than 5 percent for each gas over the entire time series.

Methodology

Emissions of CO_2 from MSW combustion include CO_2 generated by the combustion of plastics, synthetic fibers, and synthetic rubber, as well as the combustion of synthetic rubber and carbon black in tires. These emissions were calculated by multiplying the amount of each material combusted by the carbon content of the material and the fraction oxidized (98 percent). Plastics combusted in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete carbon content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete

Table 3-44: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted

Year	Waste Generation	Combusted (%)
1990	266,365,714	11.5
1991	254,628,360	10.0
1992	264,668,342	11.0
1993	278,388,835	10.0
1994	292,915,829	10.0
1995	296,390,405	10.0
1996	297,071,712	10.0
1997	308,870,755	9.0
1998	339,865,243	7.5
1999	347,089,277	7.0
2000	371,071,109	7.0
2001	404,002,786[a]	7.4[a]
2002	436,934,464	7.7
2003	436,934,464[b]	7.7[b]
2004	436,934,464[b]	7.7[b]

[a] Interpolated between 2000 and 2002 values.
[b] Assumed equal to 2002 value.

carbon content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete carbon content, and carbon black is 100 percent carbon. Emissions of CO_2 were calculated based on the number of scrap tires used for fuel and the synthetic rubber and carbon black content of the tires.

More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from municipal solid waste combustion, data on the quantity of product combusted and the carbon content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of material in municipal solid wastes and its portion combusted were taken from the *Characterization of Municipal Solid Waste in the United States* (EPA 2000c, 2002a, 2003, 2005a). For synthetic rubber and carbon black in scrap tires, this information was provided by the *U.S. Scrap Tire Markets 2003* (RMA 2004) and *Scrap Tires, Facts and Figures* (STMC 2000, 2001, 2002, 2003, 2004). Data were not available for 2004, so the values were assumed to equal the value for 2003.

Average carbon contents for the "Other" plastics category, synthetic rubber in municipal solid wastes, and synthetic fibers were calculated from 1998 production statistics, which divide their respective markets by chemical compound. For synthetic rubber in scrap tires information about scrap tire composition was taken from the Scrap Tire Management Council's internet site (STMC 2003).

The assumption that 98 percent of organic carbon is oxidized (which applies to all municipal solid waste combustion categories for CO_2 emissions) was reported in the EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2002b).

Combustion of municipal solid waste also results in emissions of N_2O. These emissions were calculated as a function of the total estimated mass of municipal solid waste combusted and an emission factor. The N_2O emission estimates are based on different data sources. As noted above, N_2O emissions are a function of total waste combusted in each year; for 1990 through 2003, these data were derived from the information published in *BioCycle* (Kaufman et al 2004). As for the activity data for CO_2 emissions, data on total waste combusted was not available for 2004, so the value for this year was assumed to equal the most recent value available (2003). Table 3-44 provides data on municipal solid waste generation and percentage combustion for the total waste stream. The emission factor of N_2O emissions per quantity of municipal solid waste combusted is an average of values from IPCC's *Good Practice Guidance* (2000).

EPA (2005b) provided emission estimates for NO_x, CO, and NMVOCs from waste incineration and open burning, which were determined using industry published production data and applying average emission factors.

Uncertainty

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from municipal solid waste combustion. IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the *Municipal Solid Waste in the United States* reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus,

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from Municipal Solid Waste Combustion (Tg CO_2 Eq. and Percent)

Source	Gas	2004 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Municipal Solid Waste Combustion	CO_2	19.4	16.4	21.1	-15%	+10%
Municipal Solid Waste Combustion	N_2O	0.5	0.1	1.3	-73%	+157%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Table 3-46: U.S. Municipal Solid Waste Combusted, as Reported by EPA and BioCycle (Metric Tons)

Year	EPA	BioCycle
1990	28,855,809	30,632,057
1991	27,773,783	25,462,836
1992	29,568,442	29,113,518
1993	28,696,188	27,838,884
1994	29,532,844	29,291,583
1995	32,182,194	29,639,040
1996	32,831,450	29,707,171
1997	33,597,844	27,798,368
1998	31,205,358	25,489,893
1999	30,859,134	24,296,249
2000	30,571,624	25,974,978
2001	30,416,919	29,694,205[a]
2002	30,340,252	33,643,954
2003	29,995,479	NA
2004	NA	NA

NA (Not Available)
[a] Interpolated between 2000 and 2002 values.

uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, carbon content of carbon black).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Municipal solid waste combustion CO_2 emissions in 2004 were estimated to be between 16.36 and 21.11 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 15 percent below to 9 percent above the 2004 emission estimate of 19.36 Tg CO_2 Eq. Also at a 95 percent confidence level, municipal solid waste combustion N_2O emissions in 2004 were estimated to be between 0.14 and 1.34 Tg CO_2 Eq. This indicates a range of 73 percent below to 157 percent above the 2004 emission estimate of 0.52 Tg CO_2 Eq.

The uncertainties in the waste combustion emission estimates arise from both the assumptions applied to the data and from the quality of the data.

- *MSW Combustion Rate.* A source of uncertainty affecting both fossil CO_2 and N_2O emissions is the estimate of the MSW combustion rate. The EPA (2000c, 2002a,

2003) estimates of materials generated, discarded, and combusted carry considerable uncertainty associated with the material flows methodology used to generate them. Similarly, the *BioCycle* (Glenn 1999, Goldstein and Matdes 2000, Goldstein and Matdes 2001, Kaufman et al. 2004) estimate of total waste combustion—used for the N_2O emissions estimate—is based on a survey of state officials, who use differing definitions of solid waste and who draw from a variety of sources of varying reliability and accuracy. The survey methodology changed significantly and thus the results reported for 2002 are not directly comparable to the earlier results (Kaufman et al. 2004), introducing further uncertainty. Despite the differences in methodology and data sources, the two references—the EPA's Office of Solid Waste (EPA 2000a, 2002b, 2003) and the *BioCycle* series—provide estimates of total solid waste combusted that are relatively consistent (see Table 3-46).

- *Fraction Oxidized.* Another source of uncertainty for the CO_2 emissions estimate is fraction oxidized. Municipal waste combustors vary considerably in their efficiency as a function of waste type, moisture content, combustion conditions, and other factors. Despite this variability in oxidation rates, a value of 98 percent was assumed for this analysis.

- *Missing Data on Municipal Solid Waste Composition.* Disposal rates have been interpolated when there is an incomplete interval within a time series. Where data are not available for years at the end of a time series (1990, 2004), they are set equal to the most recent years for which estimates are available.

- *Average Carbon Contents.* Average carbon contents were applied to the mass of "Other" plastics combusted, synthetic rubber in tires and municipal solid waste, and synthetic fibers. These average values were estimated from the average carbon content of the known products recently produced. The true carbon content of the combusted waste may differ from this estimate depending on differences in the chemical formulation between the known and unspecified materials, and differences between the composition of the material disposed and that produced. For rubber, this uncertainty is probably small since the major elastomers' carbon contents range from 77 to 91 percent; for plastics, where carbon contents range from 29 to 92 percent, it may

be more significant. Overall, this is a small source of uncertainty.

- *Synthetic/Biogenic Assumptions.* A portion of the fiber and rubber in municipal solid waste is biogenic in origin. Assumptions have been made concerning the allocation between synthetic and biogenic materials based primarily on expert judgment.

- *Combustion Conditions Affecting N_2O Emissions.* Because insufficient data exist to provide detailed estimates of N_2O emissions for individual combustion facilities, the estimates presented exhibit high uncertainty. The emission factor for N_2O from municipal solid waste combustion facilities used in the analysis is an average of default values used to estimate N_2O emissions from facilities worldwide (Johnke 1999, UK: Environment Agency 1999, Yasuda 1993). These factors span an order of magnitude, reflecting considerable variability in the processes from site to site. Due to a lack of information on the control of N_2O emissions from MSW combustion facilities in the United States, the estimate of zero percent for N_2O emissions control removal efficiency also exhibits uncertainty.

Recalculations Discussion

Historical waste combustion activity data were modified according to the updated *Characterization of Municipal Solid Waste in the United States* (EPA 2005a) report, which affected estimates for CO_2 emissions in previous inventory years. Additionally, historical estimates for N_2O emissions from waste combustion increased slightly due to an updated emissions factor. Overall, changes resulted in an average annual increase in CO_2 emissions from waste combustion of less than 0.05 Tg CO_2 Eq. (0.2 percent) for the period 1990 through 2003, and an average annual increase in N_2O emissions of 0.1 Tg CO_2 Eq. (14 percent) over the same period.

3.10. Natural Gas Flaring and Indirect Greenhouse Gas Emissions from Oil and Gas Activities (IPCC Source Category 1B2)

The flaring of natural gas from on- and off-shore oil wells is a small source of CO_2. In addition, oil and gas activities also release small amounts of NO_x, CO, and NMVOCs. This source accounts for only a small proportion of overall emissions of each of these gases. Emissions of NO_x, and CO from petroleum and natural gas production activities were both less than 1 percent of national totals, while NMVOC and SO_2 emissions were roughly 2 percent of national totals.

The flaring (i.e., combustion) and venting of natural gas during petroleum production result in the release of CO_2 and CH_4 emissions, respectively. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent may be vented, with the remaining 80 percent flared, but it is now believed that flaring accounts for an even greater proportion. Studies indicate that the

Table 3-47: CO_2 Emissions from On-Shore and Off-Shore Natural Gas Flaring (Tg CO_2 Eq.)

Location	1990		1998	1999	2000	2001	2002	2003	2004
On-Shore Flaring	5.5		6.3	6.7	5.5	5.9	6.0	5.9	5.9
Off-Shore Flaring	0.3		0.3	0.3	0.2	0.2	0.2	0.2	0.2
Total Flaring	**5.8**		**6.6**	**6.9**	**5.8**	**6.1**	**6.2**	**6.1**	**6.0**

Note: Totals may not sum due to independent rounding.

Table 3-48: CO_2 Emissions from On-Shore and Off-Shore Natural Gas Flaring (Gg)

Location	1990		1998	1999	2000	2001	2002	2003	2004
On-Shore Flaring	5,509		6,250	6,679	5,525	5,858	6,001	5,936	5,872
Off-Shore Flaring	296		316	264	244	236	203	155	162
Total Flaring	**5,805**		**6,566**	**6,943**	**5,769**	**6,094**	**6,204**	**6,091**	**6,034**

Note: Totals may not sum due to independent rounding.

Table 3-49: NO$_x$, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO$_x$	CO	NMVOCs
1990	139	302	555
1998	130	332	440
1999	109	145	414
2000	111	146	389
2001	113	147	400
2002	135	116	340
2003	135	116	341
2004	135	116	341

percentage of natural gas that is flared from off-shore U.S. production is considerably lower (approximately 30 percent in 2003), due in part to differences in the legislation governing on- and off-shore natural gas production. CH$_4$ emissions from venting are accounted for in the Petroleum Systems source category. For 2004, total CO$_2$ emissions from flaring activities were estimated to be 6.0 Tg CO$_2$ Eq. (6,034 Gg), an increase of 4 percent from 1990 levels. On-shore flaring activities accounted for 5.9 Tg CO$_2$ Eq. (5,872 Gg), or 97 percent, of the total flaring emissions, while off-shore flaring constituted 0.2 Tg CO$_2$ Eq. (162 Gg), or 3 percent, of the total (see Table 3-47).

In addition, oil and gas activities, including production, transportation, and storage, result in the release of small amounts of NO$_x$, CO, and NMVOCs. Indirect greenhouse gas emissions from this source from 1990 to 2004 are presented below (see Table 3-49).

Methodology

Estimates of CO$_2$ emissions from on- and off-shore natural gas flaring were prepared using an emission factor of 54.71 Tg CO$_2$ Eq./QBtu of flared gas, and an assumed flaring efficiency of 100 percent. Indirect greenhouse gas emission estimates for NO$_x$, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Total on-shore natural gas vented and flared was taken from EIA's *Natural Gas Annual* (EIA 2004); however, there is a discrepancy in the time series. One facility in Wyoming had been incorrectly reporting CO$_2$ vented as CH$_4$. EIA noted and corrected these data in the *Natural Gas Annual 2000* (EIA 2001) for the years 1998 and 1999 only. Data for 1990 through 1997 were adjusted by assuming a proportionate share of CO$_2$ in the flare gas for those years as for 1998 and 1999. The adjusted values are provided in Table 3-50. It was assumed that all reported vented and flared gas was flared. This assumption is consistent with that used by EIA in preparing their emission estimates, under the assumption that many states require flaring of natural gas (EIA 2000b). The emission and thermal conversion factors were also provided by EIA (2001) and are included in Table 3-50.

The total off-shore natural gas vented and flared was obtained from the Minerals Management Service's OGOR-B reports (MMS 2004). The percentage of natural gas flared was estimated using data from a 1993 air quality study

Table 3-50: Total Natural Gas Reported Vented and Flared (Million Ft³) and Thermal Conversion Factor (Btu/Ft³)

Year	Vented and Flared (original)	Vented and Flared (revised)*	Thermal Conversion Factor
1990	150,415	91,130	1,105
1991	169,909	92,207	1,108
1992	167,519	83,363	1,110
1993	226,743	108,238	1,106
1994	228,336	109,493	1,105
1995	283,739	144,265	1,106
1996	272,117	135,709	1,109
1997	256,351	124,918	1,107
1998	103,019	103,019	1,109
1999	110,285	110,285	1,107
2000	91,232	91,232	1,107
2001	96,913	96,913	1,105
2002	99,178	99,178	1,106
2003	98,113	98,113	1,106
2004	97,047	97,047	1,106

* Wyoming venting and flaring estimates were revised. See text for further explanation.

Table 3-51: Volume Flared Offshore (MMcf) and Fraction Vented and Flared (Percent)

Natural Gas Flaring	1990		1998	1999	2000	2001	2002	2003	2004
Total Gulf of Mexico (GOM) Vented & Flared (MMcf)	13,610		16,280	14,057	12,971	12,990	12,412	10,646	10,296
Estimated Flaring Fraction of GOM Vented & Flared	36%		32%	31%	31%	30%	27%	24%	26%
Total	**4,900**		**5,210**	**4,358**	**4,021**	**3,897**	**3,351**	**2,555**	**2,677**

and emissions inventory of the Gulf of Mexico (MOADS) and a 2000 emissions inventory conducted for the Breton National Wilderness Area Management Plan (BOADS). See Table 3-51.

Emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations were obtained from preliminary data (EPA 2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Uncertainty

No quantitative uncertainty analysis was conducted to determine the level of uncertainty associated with emissions from natural gas flaring.

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning the flaring efficiency and the correction factor applied to 1990 through 1997 venting and flaring data. Uncertainties in indirect greenhouse gas emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

Recalculations Discussion

The historical data for natural gas flaring was adjusted slightly, which resulted in an average annual decrease in CO_2

emissions from flaring of less than 0.05 Tg (0.1 percent) for the period 1990 through 2003.

3.11. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are currently not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[49] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997).[50]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4, N_2O, CO, NO_x, NMVOCs, particulate matter, and SO_2.[51] Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[52] Emissions from ground transport activities—by road vehicles and trains—even when crossing international

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[49] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[50] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[51] Sulfur dioxide emissions from jet aircraft and marine vessels, although not estimated here, are mainly determined by the sulfur content of the fuel. In the United States, jet fuel, distillate diesel fuel, and residual fuel oil average sulfur contents of 0.05, 0.3, and 2.3 percent, respectively. These percentages are generally lower than global averages.

[52] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[53]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4, N_2O, CO, NO_x, and NMVOC emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4, CO, and NMVOCs are the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O and NO_x are primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. The impact of NO_x on atmospheric chemistry depends on the altitude of the actual emission. The cruising altitude of supersonic aircraft, near or in the ozone layer, is higher than that of subsonic aircraft. At this higher altitude, NO_x emissions contribute to stratospheric ozone depletion.[54] At the cruising altitudes of subsonic aircraft, however, NO_x emissions contribute to the formation of tropospheric ozone. At these lower altitudes, the positive radiative forcing effect of ozone has enhanced the anthropogenic greenhouse gas forcing.[55] The vast majority of aircraft NO_x emissions occur at these lower cruising altitudes of commercial subsonic aircraft (NASA 1996).[56]

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Table 3-52: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	1998	1999	2000	2001	2002	2003	2004
CO_2	113.5	114.6	105.2	101.4	97.8	89.5	84.1	94.5
Aviation	46.2	56.7	58.8	60.5	59.3	61.8	59.4	59.9
Marine	67.3	57.9	46.4	40.9	38.5	27.7	24.6	34.6
CH_4	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Aviation	+	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.9
Aviation	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Marine	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.3
Total	114.6	115.7	106.3	102.4	98.8	90.4	84.9	95.5

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

[53] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

[54] Currently, only military supersonic aircraft fly at these altitudes.

[55] However, at this lower altitude, ozone does little to shield the earth from ultraviolet radiation.

[56] Cruise altitudes for civilian subsonic aircraft generally range from 8.2 to 12.5 km (27,000 to 41,000 feet).

Table 3-53: CO$_2$, CH$_4$, N$_2$O, and Indirect Greenhouse Gas Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1998	1999	2000	2001	2002	2003	2004
CO$_2$	113,503	114,557	105,228	101,366	97,815	89,489	84,083	94,499
Aviation	46,230	56,657	58,799	60,507	59,337	61,787	59,448	59,912
Marine	67,272	57,900	46,429	40,859	38,477	27,701	24,635	34,587
CH$_4$	8	7	6	6	5	4	4	5
Aviation	1	2	2	2	2	2	2	2
Marine	7	6	5	4	4	3	2	3
N$_2$O	3	3	3	3	3	3	2	3
Aviation	1	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1	1
CO	115	127	124	124	120	118	112	119
Aviation	76	93	97	100	98	102	98	99
Marine	39	34	27	24	23	16	15	20
NO$_x$	1,985	1,778	1,478	1,334	1,266	988	900	1,167
Aviation	182	224	233	240	235	245	236	237
Marine	1,803	1,554	1,245	1,095	1,031	743	664	930
NMVOCs	59	55	48	44	42	35	32	40
Aviation	11	14	15	15	15	15	15	15
Marine	48	41	33	29	27	20	18	25

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-54: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	1998	1999	2000	2001	2002	2003	2004
U.S. Carriers	1,954	2,462	2,625	2,737	2,619	2,495	2,418	2,465
Foreign Carriers	2,051	3,009	3,086	3,162	3,113	3,537	3,377	3,353
U.S. Military	862	502	488	480	524	482	473	498
Total	4,867	5,973	6,199	6,380	6,255	6,515	6,268	6,316

Note: Totals may not sum due to independent rounding.

In comparison to aviation, the atmospheric impacts of NO$_x$ from shipping are relatively minor, as the emissions occur at ground level.

Overall, aggregate greenhouse gas emissions in 2004 from the combustion of international bunker fuels from both aviation and marine activities were 95.5 Tg CO$_2$ Eq., or 17 percent below emissions in 1990 (see Table 3-52). Although emissions from international flights departing from the United States have increased significantly (30 percent), emissions from international shipping voyages departing the United States have decreased by 49 percent since 1990. The majority of these emissions were in the form of CO$_2$; however, small amounts of CH$_4$ and N$_2$O were also emitted. Emissions of NO$_x$ by aircraft during idle, take-off, landing and at cruising altitudes are of primary concern because of their effects on ground-level ozone formation (see Table 3-53).

Methodology

Emissions of CO$_2$ were estimated by applying of carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO$_2$ from Fossil Fuel Combustion. Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from the EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Heat content and density conversions were taken from EIA (2005) and USAF (1998). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH$_4$, N$_2$O, CO, NO$_x$, and NMVOCs were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode.

Table 3-55: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004
Residual Fuel Oil	4,781	3,974	3,272	2,967	2,846	1,937	1,597	2,363
Distillate Diesel Fuel & Other	617	627	308	290	204	158	137	167
U.S. Military Naval Fuels	522	518	511	329	318	348	459	530
Total	**5,920**	**5,119**	**4,091**	**3,586**	**3,368**	**2,443**	**2,193**	**3,059**

Note: Totals may not sum due to independent rounding.

Emission factors used in the calculations of CH_4, N_2O, CO, NO_x, and NMVOC emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4, 0.1 for N_2O, 5.2 for CO, 12.5 for NO_x, and 0.78 for NMVOCs. For marine vessels consuming either distillate diesel or residual fuel oil the following values, in the same units, except where noted, were employed: 0.32 for CH_4, 0.08 for N_2O, 1.9 for CO, 87 for NO_x, and 0.052 g/MJ for NMVOCs. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT 1991 through 2005). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 1991 through 2005). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT (1991 through 2005) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Services' total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2004). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-54. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2005). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2004). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-55.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[57]

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[57] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT (1991 through 2005) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1991 through 2005) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[58]

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[59]

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[58] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

[59] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

There is also concern as to the reliability of the existing DOC (1991 through 2005) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Historical activity data for aviation was slightly revised for both U.S. and foreign carriers. These changes were due to revisions to international fuel cost for foreign carriers and international jet fuel consumption for U.S. carriers, provided by DOT (2005). These historical data changes resulted in minimal changes to the emission estimates for 1999 through 2003, which averaged to an annual increase in emissions from international bunker fuels of less than 0.1 Tg CO_2 Eq. (0.2 percent) in CO_2 emissions, annual increase of less than 0.1 Tg CO_2 Eq. (less than 0.2 percent) in CH_4 emissions, and annual increase of less than 0.1 Tg CO_2 Eq. (0.2 percent) in N_2O emissions.

3.12. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates CO_2. However, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

In 2004, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 191.7 Tg CO_2 Eq. (191,737 Gg) (see Table 3-56 and Table 3-57). As the largest consumer of woody biomass, the industrial sector was responsible for 71 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 18 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Biomass-derived fuel consumption in the United States consisted primarily of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. These fuels burn cleaner than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

Table 3-56: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1998	1999	2000	2001	2002	2003	2004
Industrial	135.3	150.5	152	153.6	135.4	131.1	128	135.9
Residential	59.9	39.9	42.7	44.7	38.2	32.3	37.0	34.3
Commercial	4.0	5.0	5.4	5.5	4.2	4.0	4.1	4.2
Electricity Generation	13.3	14.1	14.2	13.9	13.0	15.5	17.3	17.3
Total	**212.5**	**209.5**	**214.3**	**217.6**	**190.8**	**182.9**	**186.3**	**191.7**

Note: Totals may not sum due to independent rounding.

Table 3-57: CO$_2$ Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990		1998	1999	2000	2001	2002	2003	2004
Industrial	135,347		150,510	152,019	153,559	135,413	131,079	127,970	135,943
Residential	59,911		39,920	42,677	44,685	38,153	32,267	37,019	34,270
Commercial	4,037		4,963	5,394	5,481	4,175	4,037	4,100	4,246
Electricity Generation	13,252		14,097	14,233	13,851	13,034	15,487	17,250	17,278
Total	**212,547**		**209,490**	**214,323**	**217,577**	**190,776**	**182,878**	**186,339**	**191,737**

Note: Totals may not sum due to independent rounding.

Table 3-58: CO$_2$ Emissions from Ethanol Consumption (Tg CO$_2$ Eq. and Gg)

Year	Tg CO$_2$ Eq.	Gg
1990	4.2	4,155
1998	7.7	7,711
1999	8.0	8,017
2000	9.2	9,188
2001	9.7	9,701
2002	11.5	11,473
2003	15.8	15,771
2004	19.5	19,493

Table 3-60: Ethanol Consumption (Trillion Btu)

Year	Trillion Btu
1990	63
1998	117
1999	122
2000	139
2001	147
2002	174
2003	239
2004	296

Table 3-59: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential	Commercial	Electricity Generation
1990	1,442	581	39	129
1998	1,603	387	48	137
1999	1,620	414	52	138
2000	1,636	433	53	134
2001	1,443	370	40	126
2002	1,396	313	39	150
2003	1,363	359	40	167
2004	1,448	332	41	168

In 2004, the United States consumed an estimated 2.96 trillion Btu of ethanol, and as a result, produced approximately 19.5 Tg CO$_2$ Eq. (19,493 Gg) (see Table 3-58) of CO$_2$ emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Methodology

Woody biomass emissions were estimated by taking U.S. consumption data (EIA 2005) (see Table 3-59), provided in energy units for the industrial, residential, commercial, and electric generation sectors, and applying two EIA gross heat contents (Lindstrom 2003). One heat content (16.953114 MMBtu/MT Wood & Wood Waste) was applied to the industrial sector's consumption, while the other heat content (15.432359 MMBtu/MT Wood & Wood Waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT Wood (Lindstrom 2003) was then applied to the resulting quantities of woody biomass to obtain CO$_2$ emissions estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO$_2$ with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an EIA emission

factor of 17.99 Tg C/QBtu (Lindstrom 2003) to U.S. ethanol consumption data that were provided in energy units (EIA 2005) (see Table 3-60).

Uncertainty

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would increase emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Recalculations Discussion

The historical data for wood biomass consumption was adjusted slightly, which resulted in an average annual decrease in emissions from wood biomass and ethanol consumption of 2.0 Tg CO_2 Eq. (0.9 percent) from 1990 through 2003.

Box 3-3: Formation of CO_2 through Atmospheric CH_4 Oxidation

CH_4 emitted to the atmosphere will eventually oxidize into CO_2, which remains in the atmosphere for up to 200 years. The global warming potential (GWP) of CH_4, however, does not account for the radiative forcing effects of the CO_2 formation that results from this CH_4 oxidation. The IPCC *Guidelines for Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) do not explicitly recommend a procedure for accounting for oxidized CH_4, but some of the resulting CO_2 is, in practice, included in the inventory estimates because of the intentional "double-counting" structure for estimating CO_2 emissions from the combustion of fossil fuels. According to the IPCC Guidelines, countries should estimate emissions of CH_4, CO, and NMVOCs from fossil fuel combustion, but also assume that these compounds eventually oxidize to CO_2 in the atmosphere. This is accomplished by using CO_2 emission factors that do not factor out carbon in the fuel that is released as in the form of CH_4, CO, and NMVOC molecules. Therefore, the carbon in fossil fuel is intentionally double counted, as an atom in a CH_4 molecule and as an atom in a CO_2 molecule.[60] While this approach does account for the full radiative forcing effect of fossil fuel-related greenhouse gas emissions, the timing is not accurate because it may take up to 12 years for the CH_4 to oxidize and form CO_2.

There is no similar IPCC approach to account for the oxidation of CH_4 emitted from sources other than fossil fuel combustion (e.g., landfills, livestock, and coal mining). CH_4 from biological systems contains carbon that is part of a rapidly cycling biological system, and therefore any carbon created from oxidized CH_4 from these sources is matched with carbon removed from the atmosphere by biological systems—likely during the same or subsequent year. Thus, there are no additional radiative forcing effects from the oxidation of CH_4 from biological systems. For example, the carbon content of CH_4 from enteric fermentation is derived from plant matter, which itself was created through the conversion of atmospheric CO_2 to organic compounds.

The remaining anthropogenic sources of CH_4 (e.g., fugitive emissions from coal mining and natural gas systems, industrial process emissions) do increase the long-term CO_2 burden in the atmosphere, and this effect is not captured in the inventory. The following tables provide estimates of the equivalent CO_2 production that results from the atmospheric oxidation of CH_4 from these remaining sources. The estimates for CH_4 emissions are gathered from the respective sections of this report, and are presented in Table 3-61. The CO_2 estimates are summarized in Table 3-62.

Table 3-61: CH_4 Emissions from Non-Combustion Fossil Sources (Gg)

Source	1990	1998	1999	2000	2001	2002	2003	2004
Coal Mining	3,900	2,990	2,807	2,679	2,644	2,500	2,611	2,682
Abandoned Coal Mines	286	328	330	343	313	288	277	269
Natural Gas Systems	6,034	5,973	5,797	6,033	5,981	5,971	5,939	5,658
Petroleum Systems	1,640	1,414	1,358	1,325	1,303	1,274	1,236	1,222
Petrochemical Production	56	80	81	80	68	72	72	77
Silicon Carbide Production	1	1	1	1	+	+	+	+
Iron and Steel Production	63	57	56	57	51	48	49	50
Total	**11,980**	**10,842**	**10,430**	**10,518**	**10,360**	**10,153**	**10,184**	**9,957**

Note: These emissions are accounted for under their respective source categories. Totals may not sum due to independent rounding.

Box 3-3: Formation of CO$_2$ through Atmospheric CH$_4$ Oxidation (continued)

Table 3-62: Formation of CO$_2$ through Atmospheric CH$_4$ Oxidation (Tg CO$_2$ Eq.)

Source	1990	1998	1999	2000	2001	2002	2003	2004
Coal Mining	10.7	8.2	7.7	7.4	7.3	6.9	7.2	7.4
Abandoned Coal Mines	0.8	0.9	0.9	0.9	0.9	0.8	0.8	0.7
Natural Gas Systems	16.6	16.4	15.9	16.6	16.4	16.4	16.3	15.6
Petroleum Systems	4.5	3.9	3.7	3.6	3.6	3.5	3.4	3.4
Petrochemical Production	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Silicon Carbide Production	+	+	+	+	+	+	+	+
Iron and Steel Production	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Total	**32.9**	**29.8**	**28.7**	**28.9**	**28.5**	**27.9**	**28.0**	**27.4**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 Tg CO$_2$ Eq.

The estimates of CO$_2$ formation are calculated by applying a factor of 44/16, which is the ratio of molecular weight of CO$_2$ to the molecular weight of CH$_4$. For the purposes of the calculation, it is assumed that CH$_4$ is oxidized to CO$_2$ in the same year that it is emitted. As discussed above, this is a simplification, because the average atmospheric lifetime of CH$_4$ is approximately 12 years.

CO$_2$ formation can also result from the oxidation of CO and NMVOCs. However, the resulting increase of CO$_2$ in the atmosphere is explicitly included in the mass balance used in calculating the storage and emissions from non-energy uses of fossil fuels, with the carbon components of CO and NMVOC counted as CO$_2$ emissions in the mass balance.[61]

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[61] See Annex 2.3 for a more detailed discussion on accounting for indirect emissions from CO and NMVOCs.